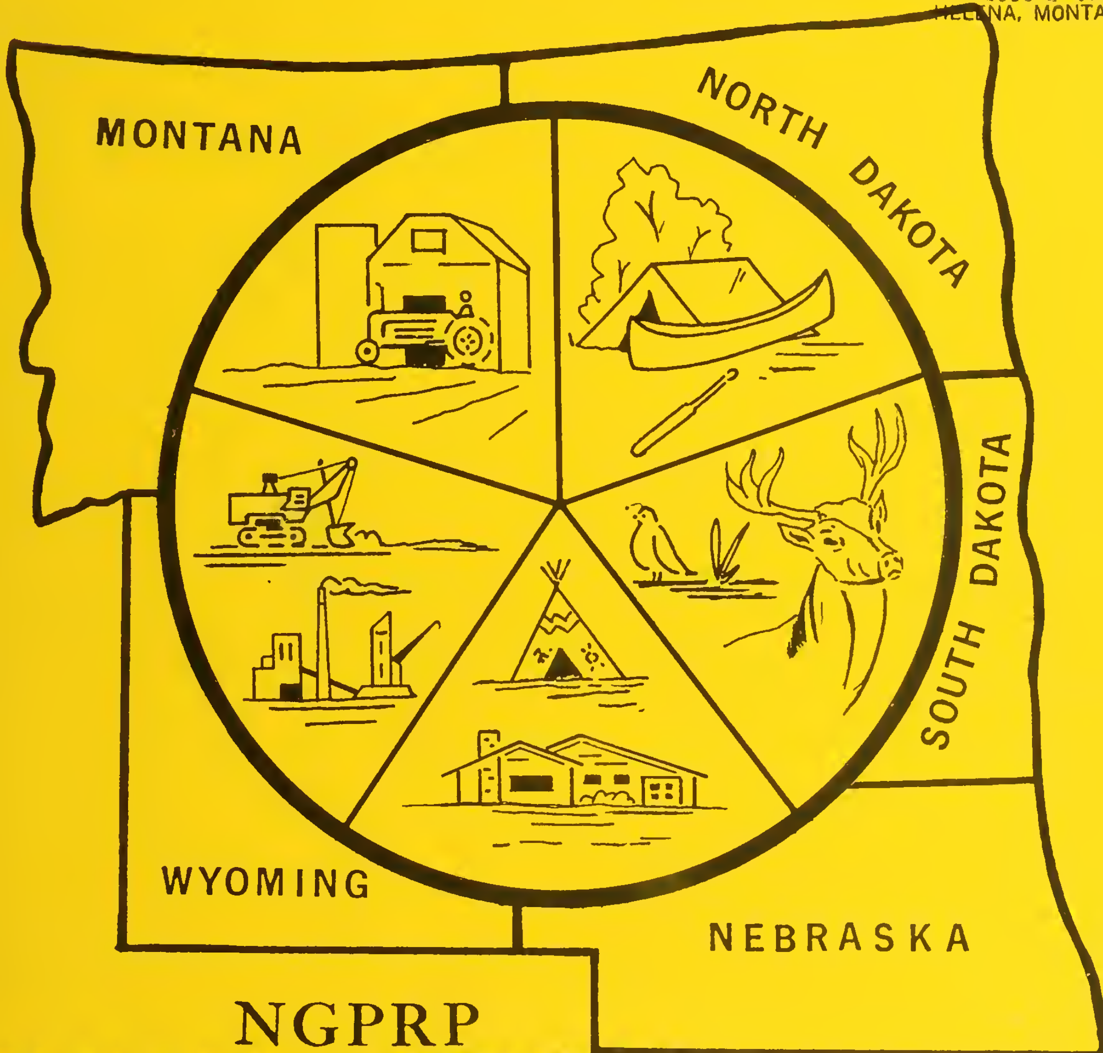
Loren L. Bahls

NORTHERN GREAT PLAINS RESOURCE PROGRAM



NGPRP

DRAFT REPORT

September 1974

MONTANA
NEBRASKA
NORTH DAKOTA
SOUTH DAKOTA
WYOMING
ENVIRONMENTAL PROTECTION AGENCY
DEPARTMENT OF AGRICULTURE
DEPARTMENT OF INTERIOR

Loren L. Bahls

NORTHERN GREAT PLAINS RESOURCES PROGRAM

COOPERATIVE RESOURCES STUDY BY:

MONTANA
NEBRASKA
NORTH DAKOTA
SOUTH DAKOTA
WYOMING
ENVIRONMENTAL PROTECTION AGENCY
DEPARTMENT OF AGRICULTURE
DEPARTMENT OF INTERIOR

Coordinated by:

THE NORTHERN GREAT PLAINS RESOURCES PROGRAM STAFF
DENVER, COLORADO AND WASHINGTON, D.C.

September 1974

NGPRP

Northern Great Plains Resources Program

ROOM 690, BUILDING 67
DENVER FEDERAL CENTER
DENVER, COLORADO 80225

September 27, 1974

LETTER OF TRANSMITTAL

To: Northern Great Plains Resources Program Participants

From: Program Management Team

Subject: Review of Draft Northern Great Plains Resources Program Interim Report

Enclosed is an incomplete draft of the Northern Great Plains Resources Program Interim Report. This draft is being forwarded so that you may have the opportunity to review the contents and provide the Program Management Team with your comments prior to final publishing of the Interim Report. Many figures and plates are presently being printed and therefore are not included in the report.

We ask that you give this report a critical review and where possible provide us with information or references which could be used to correct those faults you may identify.

The Program Management Team will revise the draft where inconsistencies are noted and will add a chapter which will discuss the issues identified by reviewers but not adequately explored in the draft report.

The reviewer should bear in mind that this draft summarizes a vast amount of information generated by the Work Groups and the NGPRP staff. It does not examine each issue in detail. Instead, it is meant to provide the reader with a general understanding of the issues associated with coal development in the Northern Great Plains and enable him to proceed toward a more critical assessment of specific issues.

Your comments should arrive at the Program Manager's office no later than November 1. The address of the Program Manager is: P.O. Box 25007, Building 67, Room 690, Denver Federal Center, Denver, Colorado 80225.

John G. VanDerwalker

John G. VanDerwalker
Program Manager

Enclosure

PREFACE

The NGPRP Interim Report is an interpretive summary and condensation of a vast amount of information assembled by seven work groups. Differences in emphasis and, to a lesser extent, in the conclusions expressed in the Interim Report, as compared with the Work Group Reports, are due mainly to the broader context in which the Interim Report was considered, and to new data and analyses performed subsequent to completion of the Work Group Reports. The Program Management Teams bears the responsibility for the conclusions of this Interim Report. These conclusions do not necessarily reflect either the positions of the participating States, Federal agencies, or the Work Group Leaders.

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These plates are presently not available but will be included in the final report. If however, the plates are received from the printer at an early date, they will be forwarded to the repositories and a notice of such action will be distributed.

PART I–INTRODUCTION

1-1. *National Energy Consumption.*–America's energy consumption has grown steadily for the past three decades. This has been the result of a population increase, increased industrial output, increased construction activities such as housing, and the ever increasing use of electrical appliances. All this has resulted in a corresponding increase in the total amount and per capita consumption of energy.

Total energy consumption grew at a rate of 4.8 percent annually for the years 1965-1970. Much of the increase in energy needed to meet this growing consumption was supplied by imported petroleum. During 1973, about 46 percent of the total energy consumed in the United States came from petroleum. Some 38 percent of this petroleum, or 17 percent of the total energy consumed, was through the use of imported petroleum.

The possibility of continuing to expand petroleum imports or increase domestic oil production to meet growing consumption is uncertain. There are physical and political constraints on how much petroleum supplies can be increased. Domestic production of natural gas is limited. Increases in hydropower production are also limited. Nuclear power may make significant contributions in the future, but its contribution has not been increasing as fast as had been expected.

The Nation thus faces the question of how it will meet its short to medium term energy requirements while alternative sources of energy are being developed.

1-2. *NGP Coal Resource.*–One possible source of fuel to meet short term energy requirements is contained in the coal resources of the Northern Great Plains (NGP). There are many reasons to consider Northern Great Plains coal. The amount of coal that can be mined is very large. There are 230 billion tons of coal in the Northern Great Plains study area 1,000 feet or less below the surface which are minable with current technology. This represents about 24 percent of our Nation's total minable coal reserve. A large proportion of this coal lies in thick beds, close to the surface, and is readily adaptable to quick and relatively inexpensive surface mining. It is much less expensive to mine than surface-mined coal located in other parts of the country and only costs one-fourth as much as the underground mining of coal. The sulfur content of NGP coal is less than most competitive eastern and midwestern coals, and reclamation costs per ton of coal

may be less than in other areas because of the high number of tons to each mined acre and the relatively flat terrain.

The coal from the NGP may be used to supply a variety of fuel demands. It could replace a portion of the high sulphur content coal which presently is being burned to generate electricity in the midwest. Power generation plants could be erected at the mine sites in the Northern Great Plains area and the electricity transmitted on high-voltage lines to areas of high demand. The Northern Great Plains coal may also be used for conversion into synthetic gas.

One consideration in assessing the prospects for Northern Great Plains coal development is its economic competitiveness as compared to using coal from other areas. Northern Great Plains coal shipped by unit trains to the midwest is, in certain areas, competitive with coal from other areas. The costs of electric generation at the mine site, or synthetic gas production, are now high when compared to conventional usage; but may become competitive as technology increases.

Environmental consideration has become increasingly important. Northern Great Plains coal is lower in sulfur content than much eastern coal, but because of its low heat value it may not be low enough in sulfur content to be burned without special emission controls. If this is the case, much of its economic advantage could be eliminated. There is also the possibility of developing the considerable resources of higher Btu low sulfur coal available in Kentucky, Tennessee, and West Virginia. Reclamation of the arid and semiarid Northern Great Plains environment is as yet unproven. Strict environmental standards may make some Northern Great Plains coals economically unavailable. All of these uncertainties make analysis of Northern Great Plains coal development both more difficult and more important.

1-3. *Concerns of the People.*—People who live in the Northern Great Plains express a variety of concerns about coal development and have diverging opinions about it—ranging from strong opposition to a favorable attitude of support. In identifying the concerns expressed by the Northern Great Plains people, it must first be recognized that the Northern Great Plains resources and lands are currently being utilized. A casual traveler gains the impression of emptiness or openness—the "Big Sky Country." The quality generating this impression is, of course, one of the region's assets. But the area is not empty. The regional resources are being used for an economy based upon agriculture, tourism, and oil and gas extraction. The areas' social, economic, and governmental structures have evolved to meet the needs of this economy.

The people of the Northern Great Plains generally express concern in terms of their own

interests. For instance, ranchers are concerned about competition for land and water. Many ranchers and farmers are concerned about the conversion of present and potential agricultural water supplies to industrial usage. Some also believe mined land cannot be reclaimed nor shallow aquifers rebuilt, and conclude they will be unable to return mined land to productive uses. Others regard coal development as a temporary disruption of the land and seek ways of taking advantage of development in ways that will improve existing agricultural conditions.

Ranchers and farmers are also concerned with air pollution and its impacts on range vegetation and crops. The businessmen who derive their livelihood from tourism as well as the tourists express concern about the impact of air pollution on the "Big Sky" atmosphere, as well as a general concern, shared by most, that the abundant wildlife resources may somehow be reduced or their values degraded.

The several Indian tribes in the region are concerned over how coal development on or near their reservations might impact their water rights, resources, and cultural values. Their concerns include the hope that coal development might provide jobs and income to alleviate poverty; the fear that with coal development they will lose control over their reservation coal resources; and that the land base, which is central to the Indian way of life, might be lost.

Perhaps the deepest concerns are for the possibility of disruption of the stable economic and social patterns of the Northern Great Plains. Both urban and rural residents are worried about the ability of their communities to absorb the anticipated labor force and the new families that will accompany coal development. They are concerned about the impact on schools, police and welfare services, sewer and water and other community services. The business community and county government managers are uncertain over the nature, size, and timing of increased population. They are worried about the time gap between the early need for their investments and the later realization of income from taxes and sales.

A more subtle concern involves the social structure of the communities. How will coal development and the resulting influx of labor and industry management change the way people live? What kind of people will the miners, construction workers, and their families be? Where will they live? What kind of new power structures will emerge and how will this affect existing social and economic groups?

Clear air, water from their streams and wells, a stable economy, comfortable social structure,

the familiarity of their towns, the quiet: this is what the people of the Northern Great Plains feel is threatened.

Not everyone is fearful about the effects of developing the coal. There are people that view the development as something good. They see increasing coal development in terms of an expanding economic base, new jobs, better services, and a chance to broaden cultural horizons. These people also have a stake in the development of the area and are anxious for it to occur.

1-4. *The Northern Great Plains Resource Program.*—The Northern Great Plains Resource Program (NGPRP) is a joint effort by the Federal and State governments, as well as industry, environmental groups, and other private individuals all of whom are concerned with the effects of coal development in the Northern Great Plains. They are concerned that the Nation has an adequate supply of energy, and at the same time, would like to be assured that energy developments proceed in a way that minimizes adverse environmental and socioeconomic impacts.

The primary objective of the Northern Great Plains Resource Program is to provide information and a comprehensive analysis that can be used to place the potential impacts of coal development into perspective and thereby assist the people of the Northern Great Plains and the Nation in the management of the natural and human resources of this region. Such management has been facilitated under the NGPRP by providing a communication and coordination link among organizations and activities dealing with the future development of the region so that they might function more efficiently and effectively.

The involvement and interest of all of the participants in the study is many fold. The lead Federal agencies—Departments of the Interior and Agriculture, and the Environmental Protection Agency—are responsible for such tasks as managing the Federal land, water and mineral resources, protecting the quality and quantity of the air and water, studying reclamation potential, and providing some services. The States' responsibilities are similar; but on a more local level. The environmental groups, industry, and other individuals all have concern in assurance that the study be as complete as time allows.

The NGPRP included a series of investigations and studies conducted by Work Groups in seven subject matter categories: Regional Geology; Mineral Resources; Water; Atmospheric Aspects; Surface Resources; Social, Economic, and Cultural Aspects; and National Energy Considerations.

The geographic area which these seven Work Groups studied included portions of Montana, Wyoming, North Dakota, South Dakota, and Nebraska. The physical resource analyses focused on the coal fields of the Fort Union Formation NGP region. Other analyses included this area, but in several instances covered a much larger portion of the States in order to treat important issues and effects of coal development.

The Work Group reports were structured to generally include a regional profile section describing present conditions in the subject field of interest; a constraints section describing the legal, institutional, and other constraints that will affect future regional energy development; and an impact analysis section describing the changes which would be expected to occur as a result of each of three alternate rates of coal development (Coal Development Profiles).

The three coal development profiles do not represent plans for development, but are instead tools designed to help measure what the effects may be at different rates of development.

One profile reflects a "low" level of future energy development–enough to supply regional energy requirements and to honor current coal export and electric power generation commitments; a second "intermediate" profile conforms to 1973 regional energy supply projections performed by the Department of the Interior; and a third, "high" profile foresees the Northern Great Plains responding to a long range National energy "emergency." The effects on the environmental, social, and economic structure of three different rates of coal development are estimated for a timespan from the present to the year 2000.

1-5. *Scope of Report.*–Time and data constraints have necessarily limited the scope and depth of this NGPRP report. These are recognized and include the following:

1. The study focuses only on coal and impacts which might occur from coal development, since this is the major issue before the public at this point, and because it appears that the environmental, social, and economic consequences of coal development would be of the greatest importance in the next few years. The area has many other energy resources, which are considered in the supply and demand analysis, but not from an impact point of view.

2. The primary impacts of the three CDPs were estimated as fully as possible. Data and time did not permit comprehensively identifying and analyzing all secondary impacts (such as the impact of major coal transportation use of railroads on availability of rail facilities for agricultural crop export or the impact of developing service industries in South Dakota or Nebraska).

3. The three CDPs were hypothesized through the year 2000. The data available indicates that the decline of the coal industry in this area would not occur until sometime after the year 2000. Consequently the impact of mine and other related facility closings was not identified and analyzed.

4. Most of the work groups found major data gaps. These are generally indicated in the text of this report and in the work group reports.

Some of the deficiencies found in this report will be addressed in future efforts of the NGPRP.

PART II–THE COAL RESOURCE OF THE NORTHERN GREAT PLAINS

2-1. *Issues.*–The Northern Great Plains region has vast coal deposits beneath its surface. But the presence of coal does not automatically ensure that it can be mined. There are a number of constraints that could occur which might impede the development of the coal. For instance, the unusual ownership pattern of minerals and surface estate may prevent many tons from ever being mined; Federal and State leasing regulations may inhibit development; or environmental considerations may preclude large amounts of coal from being used.

It is the purpose of this portion of the report to describe the coal resource and analyze the likelihood of its development and to identify and assess the several important issues confronting those considering development of NGP coal. In particular, this section will discuss:

(1) Amount of coal in the Northern Great Plains?

(2) How much of the available coal can be economically mined?

(3) How does the quality of coal affect its use?

(4) How does or how could surface and mineral ownership patterns impede production of NGP coal?

(5) Will the coal resource be large enough to meet forecasted demand even if Federal coal underlaying non-Federal surface is not available?

2-2. *The Coal Resource.*–The total estimated coal resource in the 63-county study area of Montana, North Dakota, South Dakota, and Wyoming is 1,518 billion tons[1]. Of this amount, 835 billion tons are hypothetical resources in unmapped and unexplored areas, 452 billion tons are inferred by mapping and field studies, while the remaining 231 billion tons are identified sufficiently to be classed as minable reserves. Reserves are defined as coal measured and known to be there by field studies and minable by current technology. It is not necessarily economical to extract and transport to points of use. These deposits generally include coal that is less than 1,000 feet below the surface and in beds 5 feet or more thick. This is opposed to the resource which is defined as the total amount of coal that is thought to be in the ground. The following table shows these resources:

[1]Data compiled by NGPRP from U.S. Geological Survey, U.S. Bureau of Mines, and State Geological Surveys.

Table 2-1.—*Coal resources of the 63 county study area**
billions of tons

231	Reserves, measured and indicated by studies, minable
452	Inferred studies, not considered minable
835	Hypothetical resources, unmapped and unexplored
1,518	Total resource

*Includes all lignites. Since the Minerals Work Groups completed their studies. The definitions have been redefined to exclude lignites that would have to be mined by underground methods.

The 1,518 billion tons are about one-half of the nation's total coal resource; while 231 billion tons (table 2-1) are 48 percent of the nation's minable coal reserve. Table 2-2 presents the 231-billion-ton coal reserve location by state and by mining method. The surface minable reserves shown in the second column are 5 feet or more thick with a maximum of 200 feet of overburden for the thickest beds.

Table 2-2.—*Estimated coal reserves*

Seams 5 feet or more thick
and less than 1,000 feet below surface
(in billions of tons)

State	Total reserves	Method of recovery	
		Surface mining	Underground mining
Montana	158.1	31.9	126.2
Wyoming	34.7	19.8	14.9
North Dakota	37.5	16.0	21.5
South Dakota	1.0	0.4	0.6
	231.3	*68.1	163.2

Source: NGRP Mineral Work Group report.

*The 68.1 billion tons of coal reserves at depths amenable to surface mining are shown on plate B-3.

Not all of the 68 billion tons of reserves (table 2-2) appropriate for surface mining can be recovered. It is estimated that about 20 percent cannot be economically mined because it is poorly situated topographically, that is, the reserve is located under a stream or in an area

presently considered environmentally unsound for mining. Therefore 80 percent, or about 54 billion tons, are thought to be economically recoverable[2] by present technology (table 2-3).

Table 2-3.—*Surface minable coal reserves of the NGP (in billions of tons)*

State	Reserves minable by surface methods	Recoverable reserves
Montana	31.9	25.5
Wyoming	19.8	15.8
North Dakota	16.0	12.8
South Dakota	0.4	0.3
	68.1	54.4

Source: NGPRP Mineral Work Group report.

The percentage of the 162 billion tons of coal that can be recovered by underground mining methods may be much lower. The limitations of underground mining technology and economic considerations reduce the amount that is thought to be recoverable to 82 billion tons or 50 percent of the reserves (table 2-4).

Table 2-4.—*Underground minable coal reserves of the NGP (in billions of tons)*

State	Reserves minable by underground methods*	Recoverable reserves
Montana	126.2	63.1
Wyoming	14.9	7.5
North Dakota	21.5	10.8
South Dakota	0.6	0.3
	163.2	81.7

Source: NGPRP Mineral Work Group report.

*Conventional room and pillar method.

Although the 63-county study area encompasses nearly 92 million acres, less than 3 percent, or about 2.6 million acres (table 2-5, plate B-3), are underlaid by the surface minable coal discussed above.

[2] Economically Recoverable Reserve: That part of the coal reserve that can be extracted in such a fashion as to be competitive with coal from other areas. This does not include the cost of transporting which, when added to the cost of extraction, may eleminate it from being competitive with coals from other areas.

Table 2-5.—*Acres underlaid by surface minable coal in the NGP*

State	Acres in study area millions	Acres underlaid by coal millions
Montana	34.6	1.4
North Dakota	26.7	0.7
South Dakota	11.7	0.1
Wyoming	18.6	0.4
	91.6	2.6

Source: NGPRP Surface Work Group report.

Of course not all of the 2.6 million acres underlaid by coal would be mined under any circumstances. However, additional acreage will be needed for any mine and plant facilities. In the section of this report on the Land Resource (sec. 4-2) a discussion is presented on the amount of acreage that would be disturbed for mines and plant facilities assuming three different rates of development.

Coal resources of the NGP differ in several respects from those of the rest of the nation:

(1) Costs of surface mining methods are much lower, because of the thick seams and shallow overburden.

(2) Sulfur content per Btu is lower than nearly all midwestern and most eastern coal. (Although it is not necessarily low enough to meet new source pollution standards.)

(3) High ash and water contents, and higher percentages of volatile hydrocarbons reduce the Btu content per pound considerably below that of most eastern coal (and therefore the sulfur content must be adjusted upward to compare eastern and NGP coal on a consistent sulfur per Btu basis).

The above factors all affect the marketability of the NGP coal, which is discussed in detail in section 3-6. Sulfur content deserves particular mention, since burning NGP coal may be an economical method of reducing air pollution.

A large, percentage of the enormous NGP coal resources has a sulfur content below the maximum permissible in Federal New Source Performance Standards (NSPS). (Of the samples shown in the Mineral Work Group Report, less than half will meet the standard, however the samples are not representative of volumes of coal.) These standards, for sulfur emissions per Btu, must be met by all new powerplants. They will limit sulfur emissions from a single plant, however

if the plant is located where there is a concentration of pollutants from other sources even stricter standards might be required.

While a precise assessment of the sulfur content of all the NGP coal resources is not available, as the available data does not represent a true sampling, a preliminary study reveals that a high percentage of Wyoming coal, a lower percentage of Montana coal, and nearly no lignite coal from the Dakotas, meet the New Source Performance Standards. A study was recently completed on this at the University of Illinois[3] which indicated that the NGP coal contains a much higher sulfur content per Btu than has been commonly understood.

Lignite coal is more likely to be used for gasification than for in-region power generation or coal export. Sulfur content is not critical for gasification.

2-3. ***Ownership Patterns of the Surface and Mineral Estate.***—Starting with the Homestead Act of 1862 and through succeeding Acts, the Federal Goverment granted parcels of land to anyone willing to work them. The original grants transferred the surface and mineral rights to the land but eventually the Federal Government began to reserve the coal and other mineral rights to the homestead lands that were underlaid by a known coal resource. The result is that in the homesteaded areas there is a scattered surface ownership pattern (plate 10) with the Federal Government controlling the right to mine the coal and other minerals on many acres for which it has no surface rights. For instance, in the portions of Montana, North Dakota, and Wyoming included in the NGP study area, the Federal Government controls 29 percent of the total mineral estate acreage (plate B7a and B7b). Because the Federal Government reserved the mineral rights to those acres with a known coal resource, it is estimated that over 60 percent of the total coal resource in the study area is located on the 29 percent of the mineral estate controlled by the Federal Government.[4] This 60 percent represents about 139 billion tons of the coal reserve (231 billion tons from table 2-1 times 60 percent).

Various railroad acts also contributed to a scattered ownership pattern in the study area. They provided for grants of considerable land, including coal rights, adjoining the railroad rights-of-way. As an example, the Northern Pacific Railroad was given odd-numbered sections (a section equals 1 square mile) in a checkerboard pattern for a distance of 40 miles on both sides of the right-of-way (plate B-7b). Implementation of these Acts resulted in a checkerboard pattern of Federal, railroad, and the private land ownership on either side of the right-of-way. Table 2-6 summarizes the surface and mineral ownership of the land included in the Northern Great Plains study.

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[3] Rieber, Michael "Low Sulfur Coal, A Revision of Reserve and Supply Estimates", CAC doc No. 88, center for Advanced Computation University of Illinois, 1973.

[4] U.S. Department of the Interior, Bureau of Land Management.

Table 2-6.—*Surface and mineral ownership of study area by owner and State (in percent of total)*

State (NGPRP study portion	Type of ownership	Federal acres	Indian acres	County municipal, and private acres*	State acres	Total acres million
Montana	Surface	17.0	8.2	69.0	5.8	34.6
	Mineral	33.0	7.9	53.3	5.8	
North Dakota	Surface	7.3	2.7	87.5	2.5	26.7
	Mineral	20.3	3.8	73.4	2.5	
South Dakota	Surface	5.6	16.6	71.9	5.9	11.7
	Mineral	12.1	18.0	57.0	12.9	
Wyoming	Surface	22.9	0	68.5	8.6	18.6
	Mineral	42.6	0	48.7	8.7	
Total NGP	Surface	13.9	6.0	74.7	5.4	91.6
	Mineral	28.6	6.4	58.7	6.3	

Source: NGPRP Surface Work Group report.

*Includes substantial surface and mineral rights held by the Burlington-Northern Railroad.

The scattered and mixed ownership patterns found in the NGP complicates coal development in a variety of ways. A reasonably large contiguous area is required to make mining economically feasible. Rights-of-way for access roads and railroads may be required. Where gasification plants or mine-mouth-generating operations are planned, land for plant sites and rights-of-way for powerlines and pipelines are necessary.

To combine rights to enough land having adequate coal reserves to support a logical mining unit (which in Campbell County, contains 200-500 million tons of coal) plus obtain the necessary rights-of-way, a potential coal developer may be required to deal with many private landowners as well as the Federal and State Governments. As stated previously, landowners may or may not own mineral rights on areas where they own surface rights and conversely the Federal Government often owns the mineral rights but not the surface rights.

The Federal Government has leased some mineral rights on land where the surface rights are in private ownership. A procedure for securing surface rights to land on which the mineral rights are under Federal lease was included in the Stockraising Homestead Act of 1916. This Act provided that if the surface owner is agreeable to selling or leasing his surface rights, the lessee and the surface owner must both agree to the amount of compensation the surface owner will receive.

This agreement may involve the sale of the land, compensation for damages to property that might occur, or a periodic payment for the loss of income from taking the land out of crop or grazing use. If the surface owner and the lessee cannot come to an agreement, the lessee submits a plan and posts a bond (not less than $1,000) to the Secretary of the Interior's representative[5] which would cover payment of compensation for damages. The BLM State Director then reviews the plan and the amount of bond and can either disapprove and return the plan to the lessee for revision, or can approve the plan and so notify the surface owner. The surface owner then has 30 days to appeal through the courts.

As defined by the Homestead Act of 1916, compensation is limited to those things that can be easily tabulated—fair market value replacement of a building or compensation for crops out of cultivation. But the compensation does not cover the more intangible things such as alteration of lifestyle. Determining the monetary compensation appropriately to reimburse a rancher for moving his family off a ranch and into town is a difficult problem. How can a value be placed upon living in a confined area rather than a wide open space? What compensation should be paid to a farmer unable to farm anymore? How much is personal independence worth to a man who now must depend on others? All of these questions of values will be raised more and more often in the future if increasing numbers of surface owners are asked to relinquish all or part of their farms and ranches so that the coal resource can be developed.

Recently the Senate passed a bill (S.425) that included an amendment (the Mansfield Amendment) designed to preclude many of the above questions. The solution offered by this amendment is to prevent surface mining any coal under Federal lease on land where the Federal Government does not own both the surface and mineral rights.

To better understand how this amendment, or a similar one, would affect coal development, an examination of current Federal leases in the NGP was made. It showed that two-thirds of the leased acres (including 65 percent of leased coal) could not be developed if the Federal Government had to own both surface and mineral rights. Almost none of the leases in Montana and North Dakota could be mined and only about 42 percent of the coal under lease in Wyoming could be mined. This is about 6.5 billion of the 9.8 billion tons currently under lease that could not be mined. A further evaluation was made of approximately 900,000 acres in the Decker-Birney area in Montana.[6] This region contains about 15.9 billion tons of recoverable

[5] Bureau of Land Management State Director.

[6] The area was studied by the U.S. Department of the Interior, Bureau of Land Management and the Forest Service, U.S. Department of Agriculture. It is the most intensively studied area in the NGP. Its coal reserves were evaluated by the Northern Great Plains Resource Program to determine the possible implications of S.425.

surface minable coal. The Federal Government owns both surface and mineral rights on about 79,000 of the 900,000 acres. Underlaying the 79,000 BLM acres is about 1.4 billion tons of recoverable surface minable reserves of coal. The BLM also owns the mineral rights, but not the surface rights, to lands that contain an additional 9.73 billion tons of recoverable strippable coal reserves. If S.425 or a similar bill were to become law, this 9.73 billion tons or 61 percent of the 15.9 billion tons now recoverable could not be developed. This 61 percent does not include any coal that could legally be developed, but was not in a logical mining unit.

The House of Representatives recently passed a bill (HR11500) which addressed the same questions. The bill allows Federal coal to be mined by surface methods when the Federal Government is not the surface owner, but only when the mining operator obtains the consent or acquiescence of the surface owner. The impact of this was not analyzed. The Senate and House bills are in conference committee (September 1974).

No study has been performed of the total number of Federal coal land acres under private surface ownership in the NGP study area portion of these states; however, table 2-7 below presents these data on a statewide basis ownership for the entire NGP States.

Table 2-7.—*Federal mineral and surface ownership*

State	Total acres of Federal minerals millions	Federal mineral acres under non-Federal surface ownership, millions	Percent of Federal mineral acres under non-Federal ownership
Montana	18.8	10.7	56.9
North Dakota	4.9	4.8	98.0
South Dakota	1.0	0.5	50.0
Wyoming	29.3	11.8	40.3
	54.0	27.8	52.9

Source: U.S. Department of the Interior, Bureau of Land Management.

2-4. *Federal and Other Coal Leases*.—At the present time (1974) there are 128 Federal coal leases in Montana, North Dakota, and Wyoming and none in South Dakota (plates B7a and B7b). These 128 leases include about 252,000 acres and represent a minable reserve of about 9.8 billion tons of coal (table 2-8).

Table 2-8.–*Federal coal leases in the Northern Great Plains States.*

State	Number of leases	Acres under lease thousands	Minable reserves under lease billions
Montana	17	36	1.1
North Dakota	19	16	0.3
South Dakota	0	0	0.0
Wyoming	92	200	8.4
Total	128	252	*9.8

Source: U.S. Department of the Interior, U.S. Geological Survey.

*Includes 0.6 billion tons of underground minable coal in Wyoming; the remaining 9.2 billion tons are considered surface minable.

Within the time constraint of the study it was not possible to collect information about private coal under lease in the Northern Great Plains area. A recent study by two students at the University of Wisconsin, Russell Boulding and Francis Cherry[7], provided some information about the amount of coal acreage presently under lease in the Northern Great Plains area. Table 2-9 summarizes the information contained in this study. It was compiled from numerous sources such as Federal, State, environmental groups, and other private publications. The Indian data was supplemented with Bureau of Indian Affairs information.

There are no firm estimates of how much of a coal reserve underlays leased state and private coal acres. It is estimated that there are 2.5 to 3.5 billion tons of coal under lease on the Northern Cheyenne and Crow Indian reservations in Montana. The status of these Indian leases is not clear. As a result of a recent Supreme Court decision, the Northern Cheyenne Tribe has requested the Secretary of Interior to cancel all existing leases and prospecting permits presently pertaining to their reservation. The Crow Tribe has asked that similar action be taken on their leases under which Westmorland Resources is mining Crow coal from non-Indian surface lands. Accordingly, the status of the 77,000 acres of Indian coal leases is uncertain.

[7]Boulding, Russell, and Cherry, Francis, *Coal Leasing Policy in the Northern Plains: The Complexities of Dispersed Ownership,* University of Wisconsin, 1972.

Table 2-9.—*Federal, State, private, and Indian coal acres under lease in NGP states (in thousands of acres)*

State	Federal coal acres under lease*	State coal acres under lease†	Private coal acres under lease†	Indian coal acres under lease
Montana	36	58	334	91
North Dakota	16	No data	1,000	0
South Dakota	0	No data	No data	0
Wyoming	200	400‡	—**	0
Total	252	458	1,334	91

*From U.S. Department of the Interior; Bureau of Land Management.

†Boulding-Cherry study.

‡Estimated by Boulding-Cherry study from Coal-Mineral Right Ownership Map, Powder River Basin, Cameron Engineers, July 1971. The authors stated "this is probably conservative since in Sheridan County alone 167,000 acres of State coal land had been leased as of February 1974 (letter dated April 10, 1974 from Ted Rooney, Powder River Resource Council.)."

**This information is being compiled by the Powder River Basin Resource Council.

2-5. *Mining Methods.*—

(a) *Underground Versus Surface Mining.*—The mining technology that is being used for coal energy development in the NGP is strip mining; few if any developers have shown an interest in underground mining. However, underground mining has found advocates in the NGP who see it as a method of retrieving the region's coal resources without destroying the earth's surface and others who see it as necessary to provide adequate amounts of coal over the long term.

Table 2-10 presents a comparison in broad terms of the economics, environmental impact, and safety of underground and surface mining techniques. It is clear from a strictly economic standpoint that underground mining of coal in the NGP has a weak competitive position. Compared to surface mining, capital requirements are higher; labor is scarce and productivity per man is relatively low and the actual cost of mining is, as a result, far higher.

The lower worker productivity of underground mining will increase the socio-economic impact of coal development over that caused by surface mining: because, to produce a given amount of coal it would take 8 to 10 times as many workers by conventional underground room and pillar methods and 3 to 4 times as many to produce it by longwall methods if these mining methods prove feasible in the United States. In addition, the specialized skills required by underground mining increases the probability that mine workers will come from outside the region, thereby compounding the increase in population in the NGP. The increased number of workers and total

population required of underground mining is probably the most significant difference, in terms of environmental impacts, between the mining methods.

Underground mining has been inferior from a worker safety standpoint. New mine safety regulations will improve this record, but at considerable expense. It remains uncertain as to whether this improvement will make conventional underground mining as safe as surface mining, considering the former's inherently hostile environment.

Conventional room-and-pillar mining, the usual mode of underground mining in the United States, is generally inferior to surface mining in terms of resource conservation and, possibly, environmental impact (assuming successful rehabilitation of surface-mined land). Room-and-pillar mining cannot be used to mine thick seams without low recovery ratios, even when pillars are retrieved. The most severe environmental impact of this form of mining is irregular subsidence. When it occurs, damage includes surface fissures, sinkholes, cave-ins, and an irregular lowering of the land. Horizontal displacement, combined with vertical subsidence, will alter surface and ground-water drainage patterns and allow water and air access to the underground workings. The intrusion of oxygen may lead to underground burning, and therefore, may promote air and water pollution in addition to wasting the resource. Rehabilitation and use of subsiding land is difficult if not impossible because the subsidence continues, at irregular intervals, for indefinite periods of time. Although techniques such as backfilling of material into the mines can reduce subsidence, at present this is uneconomical.

Subsidence can be controlled in some cases. When mining relatively shallow seams, removal of the pillars in conventional mining encourages subsidence to occur more rapidly leaving only strata compaction remaining. To achieve stabilization of the surface, compaction of the disturbed strata must occur. In favorable geologic areas, this controlled subsidence leaves the surface relatively intact and eliminates any need for major land rehabilitation. Longwall mining, a technique now being used in Europe, achieves this effect and is being used to mine thick seams of coal (comparable to those of the NGP) with high recovery levels and with minimum surface disturbance. Longwall mining is safer than conventional underground mining because the miners work beneath a steel roof affording protection against cave-ins.

It is doubtful though, that longwall mining, or any other type of underground mining, can be used to mine thick coal seams with thin overburden. The overburden is not likely to remain intact with subsidence resulting from the removal of thick seams. This essentially eliminates these NGP coals as a candidate for conventional underground or longwall mining, unless a

substantial technical breakthrough occurs. The extent of surface damage that would be caused by longwall mining in deeper beds of the NGP is not presently known and must await further research. Conventional underground or longwall mining of deep seams could reduce surface subsidence significantly, if not almost totally. As the overburden drops, it fractures and increases in volume. Relatively deep seams could be mined without significant surface subsidence because the increased volumes would fill the void before the fracturing reached the surface.

The reserves of both shallow surface-minable coal and deep coal minable by underground methods is abundant enough for either source to support high development levels for the short term for several decades. The "economically recoverable" surface minable coal reserve is about 54 billion tons. Although no analysis has been made of the amount of coal that could be economically extracted by longwall methods, assuming it is feasible, it would increase the total amount of coal that could be extracted, possibly dramatically. If coal remains a basic energy fuel for a long period of time, then underground mining by all available methods may eventually become a necessity to provide the coal needed. However, it seems doubtful that underground mining will supplant surface mining in the near future in the NGP unless unforeseen land rehabilitation problems occur with the latter, or unless significant technological advances in longwall mining are made in the near future.

Table 2-10.–*Comparison of surface and underground mining*

Item	Surface mining	Underground mining
1. Environmental impact		
a. Air pollution	Considerable dust problem	Potential pollution and loss of resource from underground burning, dust problem from coal refuse pile
b. Water pollution	Reclaimed areas may have greater water infiltration and retention than undisturbed areas; mining can disturb shallow aquifers; leaching from spoil piles	Subsidence can alter drainage systems, leaching from above-ground coal refuse banks

Table 2-10.—*Comparison of surface and underground mining.*—Continued

Item	Surfacing mining	Underground mining
c. Surface features	Not enough fill material for thick near-surface seams; *Topographic* reclamation is not difficult in some areas of NGP; some erosion problems in high winds, storms; revegetation is a problem in more arid areas or drought years	Surface subsidence problem substantial, can be somewhat controlled but not eliminated by longwall mining if feasible. Can be minimized or eliminated with very deep mining
2. Time lag to reach full production	6 years*	3 years†
3. Capital requirements	$35 million for 9-million-ton mines	$75 million for two 4.5-million-ton mines, conventional room and pillar
4. Coal prices at mine, 1971 average	$5.19 per ton (US), $2.42 per ton (NGP)	$8.87 per ton (US) for conventional room and pillar
5. Average labor productivity	104 tons/man/shift‡	12 tons/man/shift for conventional room and pillar**, 34 tons/man/shift for advanced European longwall§
6. Labor availability	Good, requires general construction experience	Poor, requires specialized training, work has poor image
7. Safety-fatal injuries per million short tons, 1960-70	0.2	0.7-0.8 conventional room and pillar, longwall may be significantly less
Nonfatal injuries per million short tons, 1960-70	-6	-27 conventional room and pillar, longwall may be significantly less
8. Resource conservation	80-95 percent (NGP)	*Thin seams* 40-60 percent (room and pillar) up to 85 percent (retrieving pillars if feasible) up to 90 percent (longwall, if feasible) *Thick seams* Very low conventional room and pillar. Higher for longwall if feasible

*Currently 6 years because of large number of equipment orders but may be reduced to 2-3 years with increased manufacturing capacity.

†This could increase if large backlog of orders developed.

‡Average of present high productive mines in NGP. This may increase to 170-250 tons per man-year in the future.

**National average. Would be greater with new large mines using latest technology.

§Production rate from advanced European longwall techniques. This may be improved if applied on large scale in the United States.

PART III.–ENERGY DEVELOPMENT IN THE NORTHERN GREAT PLAINS

3-1. ***Introduction***–Although 63 counties in three of the Northern Great Plains states contain 48 percent of the Nation's total coal reserve, coal production in the NGP has never been porportional to the size of these reserves. Even with recent growth, it accounted for only 32 million tons or 5.5 percent of national production in 1973 (table 3-1). The reason for this is that the major use of all coal produced in the United States is fuel for electrical generation and the Northern Great Plains region is located a much greater distance from most major centers of electric generation than are the eastern and midwestern coal fields. Even with the greater production cost per ton of eastern and midwestern coal (see table 3-2), the higher delivered price per Btu[1] at major load centers of NGP coal has kept it at competitive disadvantage.

Table 3-1.–*Production of coal in NGP states (1973)*

State	Million tons	Percent of total U.S. production
Montana	10	1.7
North Dakota	8	1.4
Wyoming	14	2.4
Total NGP	32	5.5
Total all states	590	100.0

Table 3-2.–*Estimated coal selling price per ton at mine**

Mine type	Mine production million tons per year	Selling price of coal f.o.b. mine, dollars per ton
Underground mine, 7 ft. seam	5	7.53
Strip–Wyoming	5	1.83
Strip–Montana	5	1.64
Strip–West Virginia	3	4.01

*Cost analyses of model mines for strip mining of coal in the U.S. Bureau of Mines IC-8535, 1972: Basic Estimated Capital Investment and Operating Costs for Underground Bituminous Coal Mines IC-8632, 1974.

[1] British thermal unit.

Until recently coal has been unable to economically compete with the inexpensive petroleum and natural gas available during the post-war period. In 1947, coal provided 15.8 quadrillion Btu's of energy for domestic consumption. This was 47.9 percent of total U.S. energy consumption. By 1973, coal provided only 13.5 quadrillion Btu's of energy and only 17.9 percent of the U.S. energy total requirements.

The market conditions for coal in general, and low sulfur coal in particular, have improved markedly in the past few years. The demand for low sulfur fuels created by the Clean Air Act of 1970 has put a premium on NGP coal and has expanded its market area. The mideast oil embargo, besides demonstrating the vulnerability of foreign energy supplies, created outright fuel shortages that practically eliminated price as a factor in some markets. The greatly increased prices of foreign and domestic oil have caused concurrent rises in the market price of coal, increasing the distance NGP coal could be profitably shipped. This increase in the price of foreign and domestic oil plus the strong growth in total national demand for energy has begun to outstrip the rate at which new supplies can be developed, putting development pressure on all sources of energy. Thus, there is now strong pressure to move ahead with massive development of NGP coal resources. It is the purpose of this part of the report to focus on the renewed interest in NGP coal specifically:

(1) Aspects of national energy consumption affecting production of coal from the NGP region,

(2) Other available energy sources as an alternative to using NGP coal,

(3) Characteristics of NGP coal that are advantageous or disadvantageous in helping to fulfill the national energy requirement,

(4) Effects energy conservation practices would have on the demand for NGP coal, and

(5) Effects of Federal and state policy on NGP coal production and development.

3-2. *National Energy Consumption Forecast*.—During the period 1947-1973, energy consumption increased at an average annual rate of about 3.2 percent, growing from 33.0 quadrillion Btu's in 1947 to 75.6 quadrillion Btu's in 1973. For the 5-year period 1965-1970, the growth rate was 4.8 percent; further increasing to 4.9 percent for 1972 and 1973.

The Department of the Interior[2] predicts that, without energy conservation and with an increasing percentage of energy being consumed by electric power generation, national energy

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[2] Dupree, Walter G. and West, J. R. *United States Energy Through the Year 2000* Department of the Interior, December 1972

consumption will increase from 75.6 quadrillion Btu's in 1973 to 191.9 quadrillion Btu's in 2000—an annual growth rate of 3.6 percent. During this time, per capita energy consumption will almost double going from 358.1 million Btu's annually in 1973 to 686.1 million Btu's in 2000.

Figure 3-1 illustrates the forecasted increase in U.S. energy consumption and the expected fuel sources for this increase. The Interior's forecast assumes, among other things, that:

(1) The national population would grow at a rate of 1 percent per year. (The current rate of population growth is estimated to be 0.7 percent per year.)

(2) Economic growth would be sustained at about 4.0 percent per year from 1980 to 2000 (4.3 percent through 1980). (There has been no real growth in the economy during the current year and most recent forecasts indicate slow recovery to rates similar to Interior's forecast.)

(3) Growth in industrial production would be 5 percent per year to 1980 and 4.4 percent per year thereafter.

(4) Supply limitations for fuels were explicitly taken into consideration in the above forecasts.

It should be recognized that this forecast is essentially an extrapolation of current trends based on a knowledge of how the various sectors of the economy use energy and how these sectors are growing. It does not deal explicitly with the effect of price changes on the demand and supply of energy resources, and consequently, does not recognize any energy savings or supply increases that could result from persistent increases in energy prices. Higher energy prices cause energy users to reduce energy consumption over a period of time while encouraging energy producers to produce more energy than they normally would. For this reason and because of assumption of high growth rate of both the economy and the population, the forecast may overestimate energy consumption. Others have suggested[3] lower growth rates for energy consumption (see conservation discussion, sec. 3-4). Nonetheless, the Interior forecast serves as a useful benchmark against which to gage the sufficiency of energy supplies, and the pressure for exploitation of coal resources, nationally and in the NGP region.

3-3. ***The Need for Additional Energy Supplies.***—The projected United States consumption of imported fuels in the year 2000 will almost equal the *total energy* consumption in 1973. Figure 3-2 illustrates the projected role of imported fuels in future U.S. energy consumption. Figures 3-3 through 3-6 illustrate the forecasted production and consumption of the four major sources of

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[3] See, for example, the NSF-RANN study done by Chapman, Tyrrell, and Mount as summarized in *Science*, vol. 178, No. 4062 (17 Nov. 1972), pp. 703-709. There is, however, substantial controversy over their results.

Unites States energy. The dramatic rise in the expected production of nuclear power from 853 trillion Btu's in 1973 to 47.2 quadrillion Btu's in 2000 illustrates the increasing importance being placed on this energy source. It is the only domestic source expected to make significant additional contributions, except for coal. Domestic coal production is expected to more than double in the next three decades, contributing 34 quadrillion Btu's to the national energy supply by 200. On the other hand, domestic supplies of petroleum and natural gas are generally expected to be very limited, with total oil production expected to decline and gas production to stabilize. The National Petroleum Council[4] predicts that U.S. gas production under the most favorable circumstances *could* increase by 50 percent by 1985, but at the same time, the differential between national demand and domestic production would double.

Although there will be incremental increases in geothermal, solar, and hydroelectric energy production, their total contribution is relatively insignificant when compared to the total anticipated demand (fig. 3-1).

In 1973, the United States relied mainly upon petroleum and natural gas for energy. Table 3-3 shows the sources of our present energy supply.

Table 3-3.–*U.S. energy sources, 1973*

Source	Total domestic and imported		Imported only	
	QBtu quadrillion Btu	Percent of energy consumption	QBtu	Percent of energy consumption
Petroleum	34.7	45.9	13.0	17.2
Natural gas	23.6	31.2	1.1	1.5
Coal	13.5	17.9	*	*
Hydropower and geothermal	2.9	3.9	0	0
Nuclear	0.8	1.1	0	0
Total	75.6	100.0	14.1	18.7

*The United States is a net exporter of coal.

With the higher prices recently attained by petroleum and natural gas, increased levels of exploration can be expected. Additional discoveries are expected to be found in the Outer

[4] "U.S. Energy Outlook," National Petroleum Council, Dec. 1972.

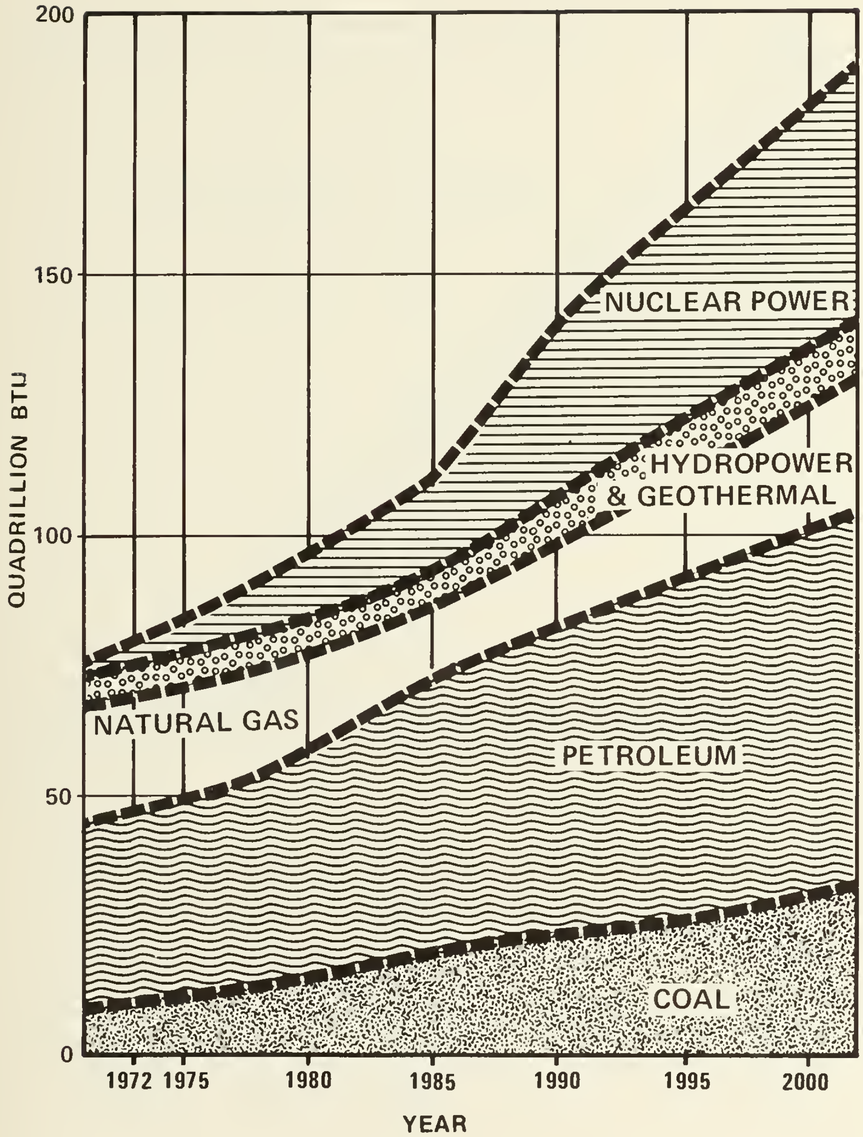


Figure 3-1. U.S. Energy Consumption by Major Source

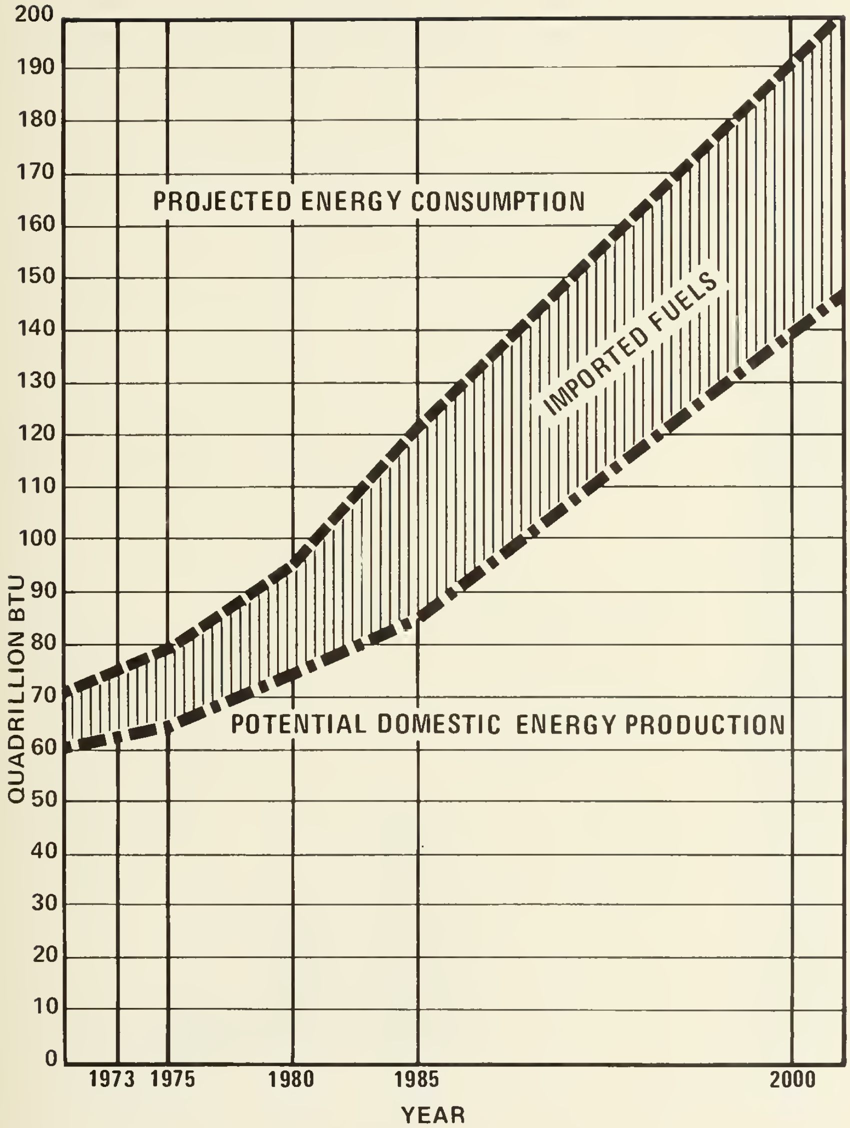


Figure 3-2. U.S. potential energy production/consumption.

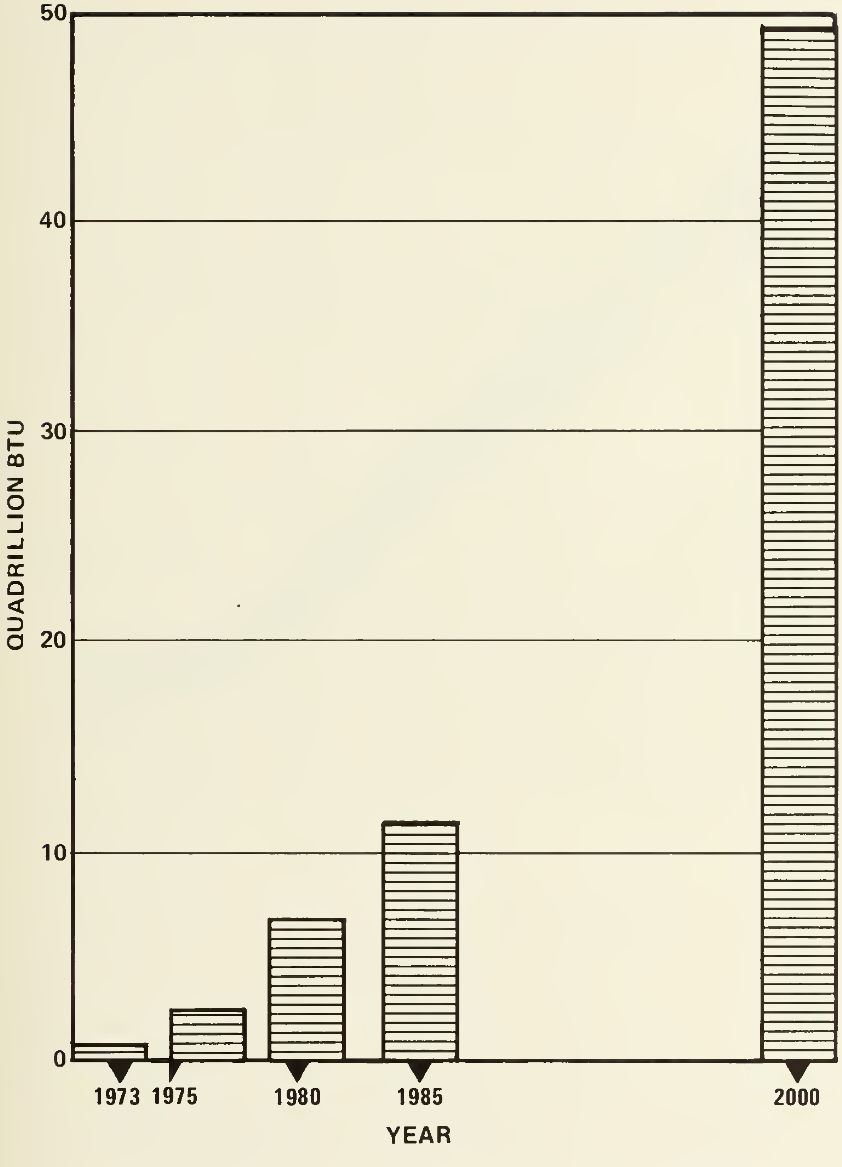
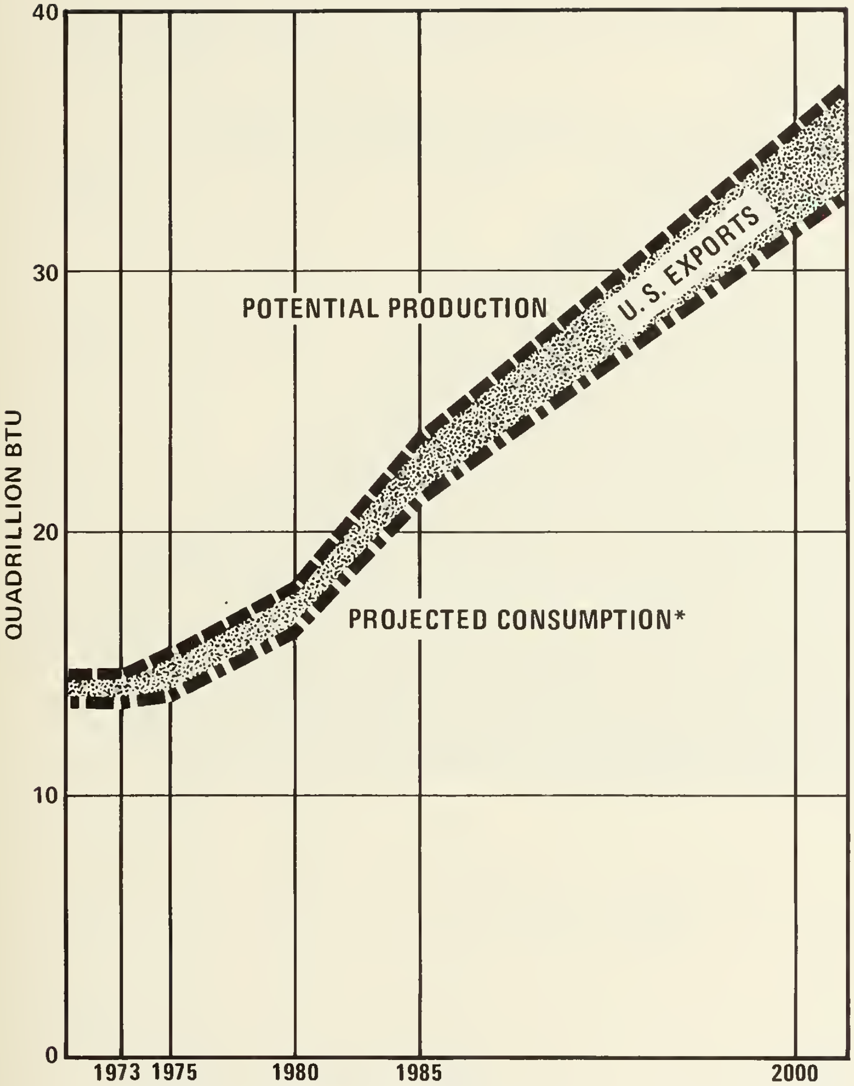


Figure 3-3. U.S. nuclear-powered electricity production/consumption.



* Includes coal consumed in generating electricity and converting coal to synthetic natural gas.

Figure 3-4. U.S. coal production and consumption.

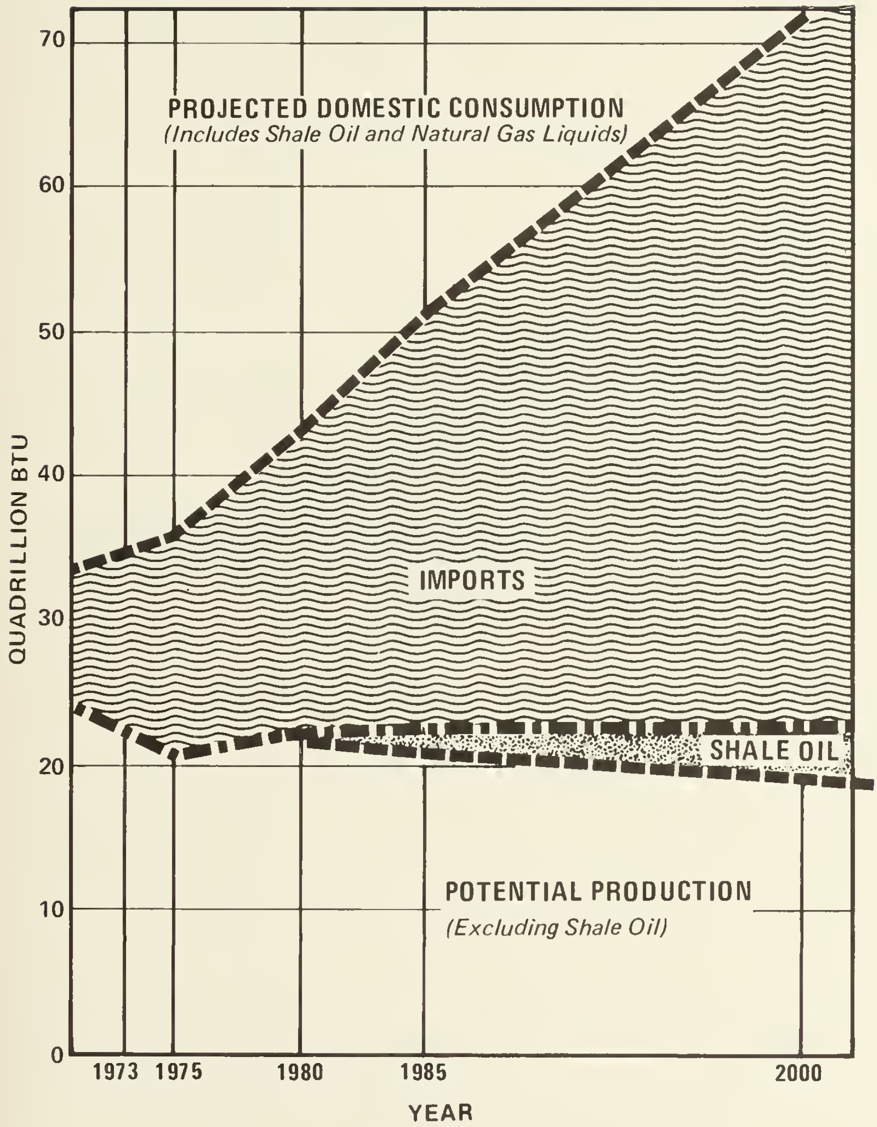


Figure 3-5. U.S. petroleum production and consumption.

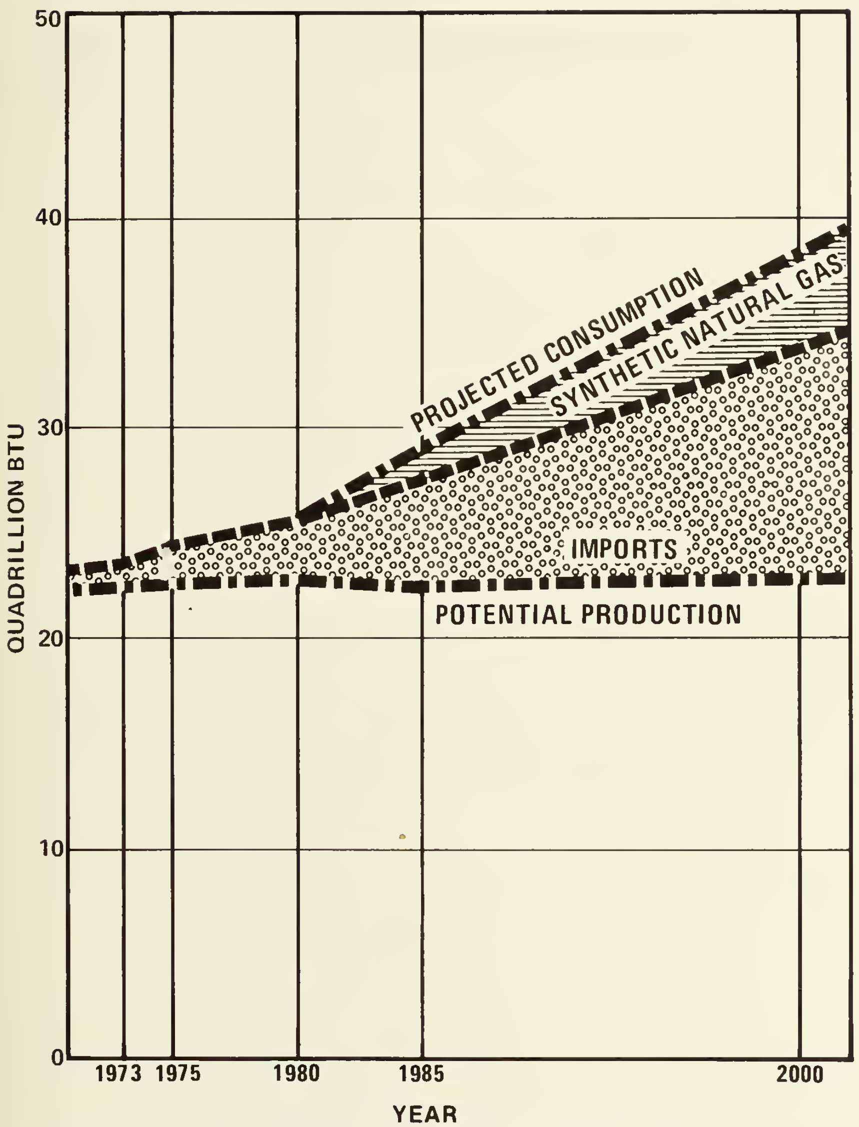


Figure 3-6. U.S. natural gas production and consumption.

Continental Shelf, particularly if leasing proceeds at the rate of 10 million acres per year that has been proposed. However, the Department of the Interior estimates that domestic oil production, including Alaskan production and shale oil, will increase from 21.7 quadrillion Btu's in 1973 to only 23.8 quadrillion Btu's in 2000. Production from the conterminous 48 states, including offshore areas but excluding shale, is projected to decline from 21.7 quadrillion Btu's to 16.3 quadrillion Btu's (see table 3-4).

Table 3-4.–*Petroleum sources*

	1973	1985	2000
Domestic supply			
Conterminous 48 states	*21.7	18.2	16.3
Alaskan north slope	–	4.1	3.4
Synthetic liquids (shale oil)		0.5	4.2
Total domestic supply	21.7	22.8	23.9

*All units quadrillion Btu (QBtu).

Natural gas prices in interstate commerce are regulated and have been held to low levels that may have discouraged exploration. At the moment, a partial deregulation–or at least a series of allowable price increases–is taking place, and general price increases are anticipated to continue. These increases are expected to stimulate exploration for new domestic sources of natural gas with additional production from new sources. Nevertheless, the Department of the Interior estimates that domestic natural gas production will remain at about 22 quadrillion Btu's through the year 2000.

The combined production of domestic petroleum and natural gas will increase from 44.2 quadrillion Btu's to 46.3 quadrillion Btu's between 1973 and 2000, including Alaskan oil and shale oil. This represents 58.5 percent of the U.S. energy consumption in 1973, but only 24.6 percent in 2000. The significance of this is that neither domestic petroleum nor natural gas can be expected to meet the increases in demand for energy through the year 2000.

These statistics show that to meet the projected increase in energy demand by 2000 without major conservation efforts, the United States will have to obtain as much as 122.7 quadrillion Btu's per year from oil and natural gas imports and from increased nuclear power and coal

production. The Department of the Interior's projection forecasts a breakdown of Btu supply as follows:

Oil imports will be at a level of 47.5 quadrillion Btu's;

Nuclear power will be increased by 46.4 quadrillion Btu's;

Coal will be increased by 17.9 quadrillion Btu's;

Natural gas imports will be at a level of 10.9 quadrillion Btu's.

If U.S. energy consumption were to continue to follow the current pattern of heavy reliance upon petroleum and natural gas, even higher levels of imports than forecasted would be necessary. Such heavy dependence upon imported energy could subject the United States to political pressures which may be unacceptable, as well as expose the United States to a potentially serious and sudden energy shortage if the foreign supply was interrupted.

3-4. ***The Potential for Energy Conservation***.–The Department of the Interior projection did not take into account the potential for energy conservation.[5]

Although there has been substantial disagreement as to the effectiveness and potential side effects of individual energy conservation strategies, there seems to be a general consensus that U.S. energy consumption is not enextricably tied to a growth curve that projects the past into the future. A vigorous conservation program could have the effect of slowing national energy demand and thus relieving some of the pressures for rapid development of energy resources throughout the Nation. The Council on Environmental Quality has established a year 2000 energy consumption level of 121 QBtu's (rather than a projected 191.9 QBtu's) as a goal.

In the absence of governmental action, a considerable amount of energy conservation can be expected in the future simply because of market pressures–as prices for energy increase the incentive to conserve energy will also increase. However, the energy market place in the United States contains many disincentives to energy conservation that could be overcome by governmental action. These disincentives include:

a. Energy prices do not reflect total costs of environmental damage, and some clean-up costs are borne by the general public rather than by energy consumers in proportion to their

[5] The projections do account, however, for expected savings in energy production and utilization efficiency. In the electrical sector, the heat rate (the heat energy needed to generate a unit of electricity for fossil-fueled powerplants) was assumed to decline from 10,494 Btu/kWhr in 1971 to 8,500 Btu/kWhr in 2000 for a 19 percent gain in efficiency. For nuclear powerplants, the heat rate was assumed to decline from 10,660 Btu/kWhr (represented Light Water Reactor technology) to 9,000 Btu/kWhr (representing a mix of light-water high-temperature gas reactors and liquid metal fast breeder reactors, for an efficiency gain of 15.5 percent). In addition, the energy input per dollar of value added in the industrial sector was assumed to decline from 101 to 79; however, part of this decline is artificial in that it reflects a bookkeeping shift of losses to the electrical sector.

consumption. Thus, energy is underpriced, discouraging some conservation measures that would be realized at prices reflecting energy's total costs.

b. Electricity rate structures favors increased consumption. Thus, large consumers who may have the most opportunity to conserve energy but are not encouraged to do so by the existing rate structure.

c. Consumers do not have adeuqate information on energy use. Although there is a wide range of efficiency among energy-using products doing the same job (automobiles, refrigerators, air conditioners, etc.), information about energy costs is often unavailable to the consumer.

d. Energy costs are paid for over a long period of time, whereas the cost of conservation measures often is reflected in the initial purchase price of the energy using products and are thus more visible and more difficult to pay for because of high interest rates.

The Government can attack these disincentives either by affecting the cost of energy (by restructuring electricity rates, taxing energy in order to recover environmental costs, providing or requiring provision of information about energy effectiveness of products, granting tax deductions for conservation measures, etc.), or by direct regulation of energy efficiency and use (by establishing minimum standards for applicance energy use and home insulation, rationing gasoline, restricting parking, etc.). Although there is considerable disagreement about which basic type of strategy is best, it seems likely that any broad governmental conservation program will contain elements from both.

There have been several recent studies that have sought to predict the effect on future energy demand that may result from the simultaneous establishment of a whole range of conservation measures. Although some of these studies are discussed below, they all appear seriously deficient in two crucial areas:

a. They lack serious in-depth analyses of the means by which the conservation measures can be implemented.

b. They fail to adequately consider the potential side effects of the measures on the U.S. economy and lifestyle. (The Ford Foundation studies discussed following have not been completed and may not deserve these criticisms upon completion.)

3-5. *Recent Studies.*–A recent National Academy of Engineering study[6] estimates potential savings from a series of energy conservation measures to be 8 to 9 MBPD (million barrels per day) of oil equivalent, or 17 to 19 QBtu (quadrillion Btu's) per year, by 1985. This represents about a 15 percent savings from expected energy levels in that year. The suggested measures include a range of industrial conservation measures yielding a 10 percent savings in industrial energy; increases in space heating efficiency and better building insulation standards; transportation improvements such as carpooling, lower speeds, improved aircraft load factors, smaller automobiles, more public transit systems; and improvements in industrial process efficiency.

The Energy Policy Project of the Ford Foundation has prepared a report on its studies in exploring energy sources.[7]. Two "alternate futures" or scenarios are presented: a "Technical Fix," which is calculated to halve the long term 3.4 percent growth rate in U.S. energy while maintaining our standard of living and avoiding major alterations in lifestyle, and a "Zero Growth Scenario" which would halt energy growth but entail very substantial changes in the U.S. economy, in residential patterns, and so forth.

Although in many ways the "Zero Growth Scenario" is the more interesting of the two, the measures necessary to achieve it–a drastic trend away from single family housing; a major shift in the U.S. economy towards agriculture and high-technology, low-energy industry (with consequent large-scale importing of high-energy products such as fertilizer and aluminum), and far greater concentration on service-oriented employment; major shifts in transportation towards fewer trips and far greater use of public transportation and so forth–are extraordinarily difficult to analyze, with respect to both their possibility of being implemented and their potential side effects.

The Technical Fix represents a 17 percent savings in total energy consumption by 1985 (over the total consumption assuming no major conservation measures) and a 35 percent savings by 2000. The actual conservation measures are quite similar in temper to those discussed in the Academy of Engineering Report.[6] The most interesting aspect of the Technical Fix is the implications it would have for energy supply. According to the report, the reduction in energy demand implied by the scenario would allow the United States to forego extensive development of some major new energy sources. For instance, the report says "the nation could choose not to

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[6] U.S. Energy Prospects–An Engineering Viewpoint, Task Force on Energy of the National Academy of Engineering, Washington, D.C., 1974.

[7] "Exploring Energy Sources", Ford Foundation, Library of Congress catalog card No. 74-77757, 1974.

expand coal mining generally, in either the East or the West, because of environmental or social problems, or to restrict surface mining in particular." For instance, a 15 percent energy savings represents a quantity of energy that is approximately *twice* as great as the entire Northern Great Plains coal energy contribution to national energy production under the High Profile in the year 2000. However, such an action would still have to be accompanied by a substantial growth in nuclear energy to prevent energy shortages.

A third prediction of potential energy conservation possibilities has recently been made by the Department of the Interior, Office of Energy Conservation. Conservation efforts which involve only increases in the efficiency of energy use, but no restrictions on energy use, such as rationing, are estimated to be capable of reducing year 2000 consumption from 191.9 to 168.8 QBtu's. Details are shown in figure 3-7.

As noted before, there is no consensus that the energy conservation strategies outlined above will achieve the predicted energy savings. It should be clear that a growth rate in U.S. energy consumption of only. 1.7 percent per year—the predicted result of the Technical Fix conservation scenario—is quite optimistic. Such a rate is half of the 20-year historical rate—and approximately *one-third* of the rate of the past half decade. Furthermore, even with such a lower rate of growth our energy supply problems will not have been solved. The report qualifies the Technical Fix scenario by saying, "if the pace and mix of economic growth remains unchanged, energy consumption . . . would resume at a higher rate of growth, beyond the year 2000, as new opportunities for cutting out waste become harder to find. Even if the . . . growth rate stays at 1.7 percent per year extended into the next century, a level of 180 quadrillion Btu's (versus 72 in 1972) would be reached by 2025 and 275 quadrillion Btu's per year by 2050."

3-6. ***Markets for Northern Great Plains Coal.***—The Interior consumption forecast provides for significant increases in coal production, with NGP coal production increasing at more than the proportional amount. Figure 3-8 and table 3-5 show the level of future NGP coal production that is consistent with the Department of the Interior's forecast (i.e., CDP II).

Table 3-5.—*Coal production—NGP and other*

	Million tons (percent of total coal production by weight)				
	1973	1975	1980	1985	2000
NGP	32 (5.4)	52 (8.2)	107 (14.5)	197 (19.6)	362 (25.5)
Other	566.5	584	633	788	1,056

The expected markets for NGP coal are:

1. Export of coal from the region, allowing its use in electric powerplants in large portions of the United States and particularly the midwest.

2. The production of synthetic natural gas from coal as less expensive sources of gas become unable to meet demands.

3. The generation of electric energy at mine-mouth plants, and other powerplants in the NGP in an effort to supply energy for use both in the NGP region and export.

The demand for Northern Great Plains coal energy—in the form of coal, CSNG (coal synthetic natural gas), or electricity from mine-mouth powerplants, is dependent not only on the demand for all energy fuels but also on the competitive position of NGP energy in each of its potential market areas. This competitive position in turn depends upon a number of factors that involve the availability, price, and environmental attractiveness of the alternative energy sources.

The predictive analysis must consider all of the following issues:

—Future environmental restrictions on exploration and exploitation of the alternative energy resources, and the consequent effect on their availability and price.

—Future national policy with respect to reliance on imported fuels, and the inverse: foreign willingness to supply fuels to U.S. markets.

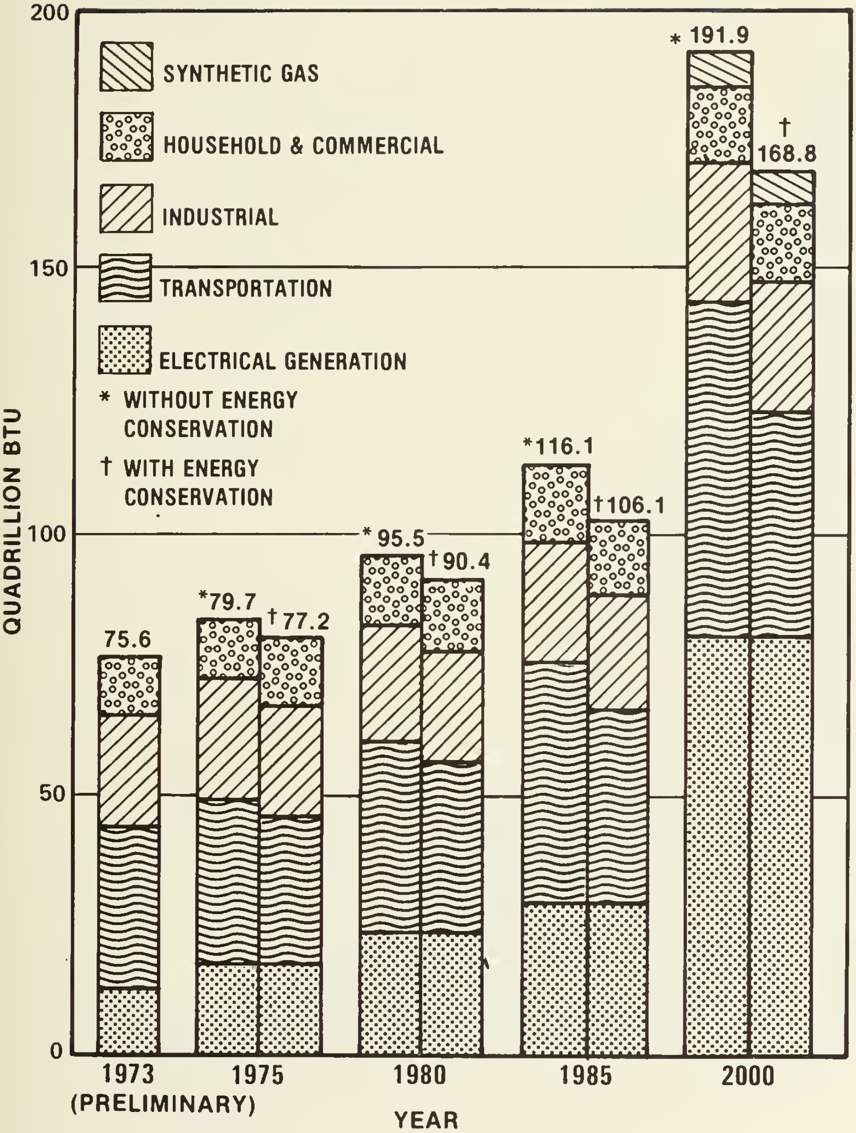
—National policy on supporting and financing new energy sources and associated research.

—Future environmental restrictions on fuels used (for instance, restrictions on the sulfur content of fuels).

—Development pace of alternative energy production and pollution control technologies.

—Future policies of utility commissions in market areas. Several of these issues will have, by themselves, a very powerful effect on the future viability of NGP energy development. At the same time, many of the issues are hard to analyze or predict.

(a) *Export Market for Northern Great Plains Coal.*—The delivered price of NGP coal in the midwest exceeds the price of indigenous midwest coal. Coal produced in mines of the NGP states is presently transported to steam-electric generating plants located in the West, North Central, and East North Central States where recently imposed mandatory limits on permissable levels of SO_2 emissions have created demand for low sulfur coals and thus, have supported the longer rail hauls and higher transportation costs. In unit-train shipments of coal from Montana and Wyoming to Minnesota and Illinois, 60-75 percent of the estimated 1973 delivered cost is accounted for by transportation.



SOURCE: U.S.D.I. OFFICE OF ENERGY CONSERVATION

Figure 3-7. Energy conservation.

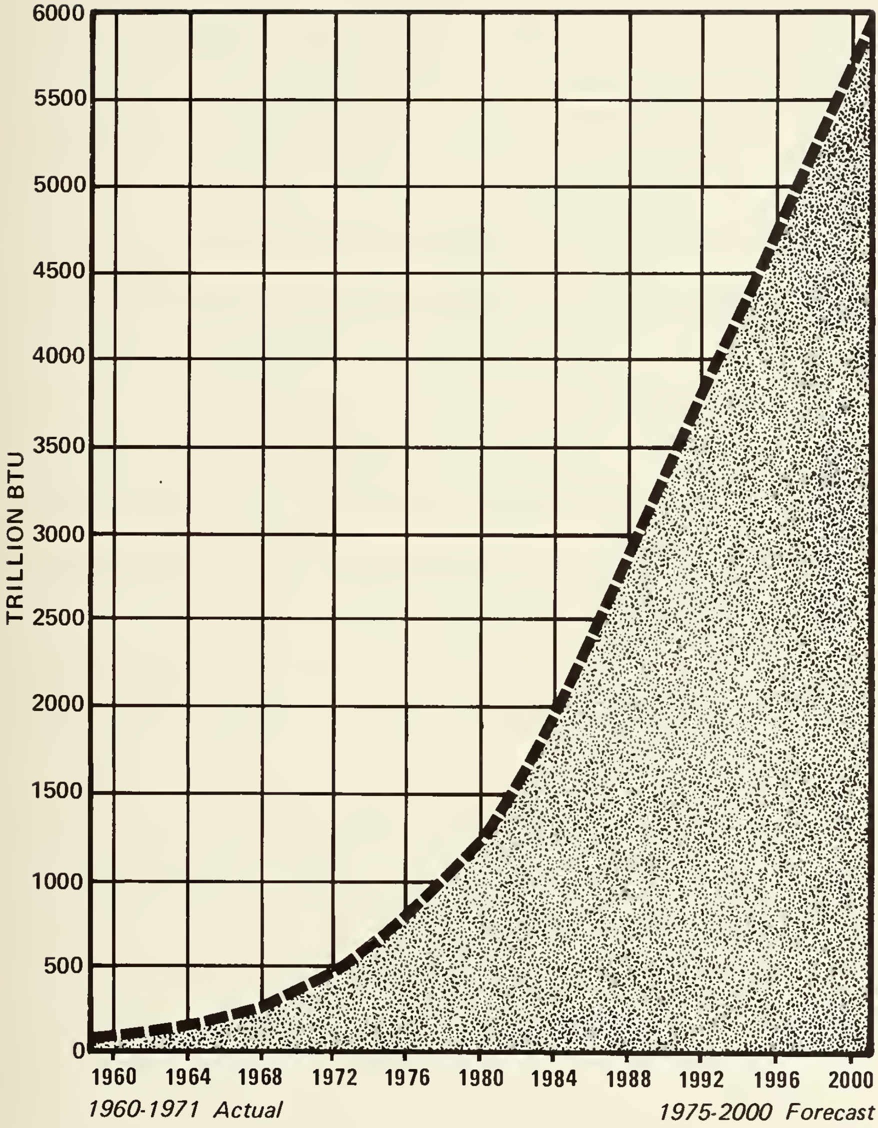


Figure 3-8. Forecast of coal production in the Northern Great Plains.

Table 3-6 illustrates the price differential for four NGP mine/midwestern market combinations. This difference ranges from 1.1 cents per million Btu's in Minnesota to 19.0 cents per million Btu's in Illinois-Indiana. Even greater differences would occur for longer hauls to the east. Column 7 of the table reflects the premium per million Btu's currently being paid over the delivered cost of midwest coal for NGP coal delivered by unit trains, and the estimated premium that would be paid if a 15 million-ton-per-year capacity slurry pipeline was the method of delivery. The data implies that a pipeline of this capacity, if justified by the volume of shipments, can deliver NGP coal to many midwestern markets at lower costs than indigenous coal. If one adds a medium estimate of the cost of emission control to the cost of midwestern coal, but not to the cost of NGP coal, unit train delivery of NGP coal will be at lower Btu cost than midwestern coal in many midwestern markets.

Despite the *current* lack of economic incentive for shipping NGP coal further than the midwest, NGP coal has been shipped as far east as West Virginia. In this latter case, the key reason seems to be that some state utility commissions have allowed an automatic pass-through of fuel transportation costs (in other words, these costs can be charged directly to the consumer without the necessity for hearings), thus allowing Western Coal to successfully "compete" with Appalachian coal that is actually priced lower.

Other factors involved in the shipment of NGP coals outside their traditional market areas include:

–The lack of availability of stack gas desulfurization equipment, which has rendered significant quantities of eastern and midwestern high sulfur coals (at least temporarily) useless (while NGP coals have been able to comply with air pollution standards).

–The past Mideast oil embargo, which forced oil-burning powerplants to compete in the coal market and drove coal prices up to levels which made long-haul coal shipments economically feasible.

The long-term market for NGP coal depends upon whether this coal can maintain its current advantage over competing midwestern and eastern coals. For example, it seems doubtful that the automatic pass-through of transportation costs will be a *long-term* factor in promoting eastern markets for NGP coal. There are large deposits of low sulfur coal in the East, especially in Kentucky. Although these are deep underground reserves and have considerably greater mining costs than do NGP coals, the high transportation costs of NGP coal may curtail its eastern markets.

Table 3-6.—*Price of NGP coal in midwest markets compared to prices of midwest coal*

Origins, destinations and transport mode	(1) Actual cost of transportation by unit trains, cents 10^6 Btu: Range	(2) Actual cost of transportation by unit trains, cents 10^6 Btu: Average	(3) Cost of transportation by slurry*	(4) 1973 coal cost f.o.b. mine in origin state cents/10^6 Btu	(5) Estimated average total cost of western coal delivered to state, cents/10^6 Btu	(6) November 1973 actual price of midwestern coal purchased by steam-electric plants in state destinations cents/10^6 Btu	(7) Difference in cents/10^6 Btu of NGP coal delivered compared to midwestern coal delivered	(8) Cost of stack gas cleaning†	(9) Price advantage of NGP coal in cents/10^6 Btu, delivered compared to midwestern coal delivered with emission controls
Montana to Minnesota (approx. 815 miles)									
Unit train	18.6 to 31.6	24.5		+ 16.2	= 40.7	39.6	1.1 more +	15.7 =	18 less
Slurry			14.6	+ 16.2	= 30.8	39.6	8.8 less +	15.7 =	28 less
Wyoming to Minnesota (approx. 1,100 miles)									
Unit train	30.5 to 32.1	31.3		+ 16.2	= 52.8	39.6	13.2 more +	15.7 =	6.1 less
Slurry			19.8	+ 16.2	= 41.3	39.6	1.7 more +	15.7 =	17.6 less
Montana to Ill.-Ind. (approx. 1,270 miles)									
Unit train	45.4 to 51.7	49.2		+ 16.2	= 65.4	46.4	19.0 more +	15.7 =	0.3 less
Slurry			22.9	+ 16.2	= 39.1	46.4	7.3 less +	15.7 =	26.6 less
Wyoming to Illinois (approx. 1,110 miles)									
Unit train	42.5 to 45.0	43.7		+ 21.5	= 65.2	46.4	18.8 more +	15.7 =	0.5 less
Slurry			20.0	+ 21.5	= 41.5	46.4	4.9 less +	15.7 =	24.2 less

*Based on 1.8 cents/million Btu/100 miles: 15 million ton/year capacity: 16.8 million Btu/ton. For 3 million ton/year capacity, the cost would be 5.3 cents/million Btu/100 miles. These estimates are modified from the Southwest Energy Study to reflect the Btu value of NGP coal.

†Sulfur Oxide Central Technology Assessment Panel—April 1973. Reflects costs of wet lime/limestone/$Ca(OH)_2$ slurry scrubbing. Number cited reflected average of 1.1-2.2 mills/kWhr adjusted by heat rate of 10,494 Btu/kWhr. $\frac{1.65 \text{ mills/kWhr}}{10{,}494 \text{ Btu/kWhr}} \times 10^6 = 157 \text{ mills}/10^6 \text{ Btu} = 15.7 \text{ cents}/10^6 \text{ Btu}$

Another uncertainty with regard to NGP coal's future export markets involves the future price and availability of adequate and reliable stack gas cleaning devices for sulfur oxides. The Environmental Protection Agency maintains[7a] that stack gas desulfurization technology is available and sufficiently reliable to warrant installation in fossil-fueled powerplants. The utility industry has in general disagreed with this position and contended that presently available equipment is too unreliable to be used in a powerplant. Whatever the present situation, however, future availability of reliable desulfurization equipment could affect NGP coal markets.

A further uncertainty in the market for NGP coal lies in the ability of NGP coal to meet low sulfur requirements imposed by the Clean Air Act. NSPS (New Source Performance Standards) for powerplants under the Act allow for only 1.2 pounds per million Btu's of SO_2 emission from powerplants. Table 3-7 shows the maximum allowable sulfur content of various quality coals based on this requirement. Half of the samples of coal from selected locations in the NGP would require the coal to be either pretreated to remove sulfur, burned in powerplants employing stack gas cleaning systems, or blended with lower sulfur coal. Data are not available on percentage of NGP coal that would require such treatment for use in powerplants. It should be noted that these controls may not be as expensive as the high efficiency SO_2 controls required for powerplants burning higher sulphur coals.

Additionally, requirements of SIP's (State Implementation Plans) under the Clean Air Act limit emissions from existing powerplants, and hence place sulfur limitations on the coal they may burn. These requirements may be more or less stringent than the NSPS; in areas of multiple sources, they may be more stringent. All of these requirements (NSPS and SIP's) are, of course designed to enable the nation to meet National Ambient Air Quality Standards, set to protect public health and welfare.

Table 3-7.–*Btu values and allowable sulfur content*

Btu value per pound	Maximum allowable sulfur content under NSPS, percent*
6,000	0.38
7,500	.47
9,000	.57
10,000	.63
12,500	.79
15,000	.95

*Assuming 95 percent conversion of sulfur to gaseous sulfur oxides.

[7a] *Final Report on Projected Utilization of Stack Gas Cleaning Systems by Steam Electric Plants*, Sulfur Oxide Control Technology Assessment Panel (SOCTAP), April 1973.

Unless outright shortages of competitive fuels occur, the delivered cost of NGP coal will play a crucial role in determining its markets. Although the analysis presented previously forecast potentially favorable cost advantages for NGP coal, these advantages were computed on the basis of 1973 prices. These price advantages may not be stable. The Interagency Coal Task Force for Project Independence has estimated the minimum delivered costs for various coals in several market areas. Figure 3-9 compares these costs for 1980. (These costs are based on allowing mine owners a 15 percent rate of return over the 25-year life of the mine.) An analysis of these estimates reveals that NGP deep-mined coals are not competitive in most market areas, usually by a very wide margin. The NGP surface-mined coals are roughly competitive with eastern and midwestern deep-mined coal in midwestern markets. Although NGP surface-mined coals are not strictly competitive with midwestern and eastern surface-mined coal on a delivered cost basis, most of these latter coals are high in sulfur content and will require a greater expense in meeting NSPS's than will the NGP coal.

Although Figure 3-9 assumes explicit values for transportation costs, in fact significant differences exist between different modes of transportation and, indeed, *within* each mode depending upon the capacity of the mode, its financing arrangements, and its configuration and management. Table 3-8 presents cost data for transporting coal in unit trains or through pipelines, and compares these to the cost of transporting coal energy, as electricity, through high-voltage transmission lines. The data shows that high-capacity slurry pipelines (where coal is mixed with water to form a suspension called "slurry," which is then shipped via pipeline) offer some potential for reducing transport costs, but the accuracy of the data for this mode is not as certain as the others due to less experience with operating slurry pipelines.

(b) *Market for NGP Synthetic Natural Gas.*—A number of energy companies have shown substantial interest in developing facilities for the production of CSNG (Coal Synthetic Natural Gas) in the Northern Great Plains states and elsewhere, and have invested in research programs and plant development planning. Companies who have announced Lurgi-type gasification projects in the Northern Great Plains include:

—Panhandle Eastern Pipe Line Co. and Peabody Coal Co. (one plant in eastern Wyoming);

—Natural Gas Pipeline Co. of America (one plant in Dunn County, North Dakota);

—Northern Natural Gas Co. and Cities Service Gas Co. (four plants in the Powder River Basin);

—Michigan Wisconsin Pipeline Co. (several plants in North Dakota, first plant planned for 1980).

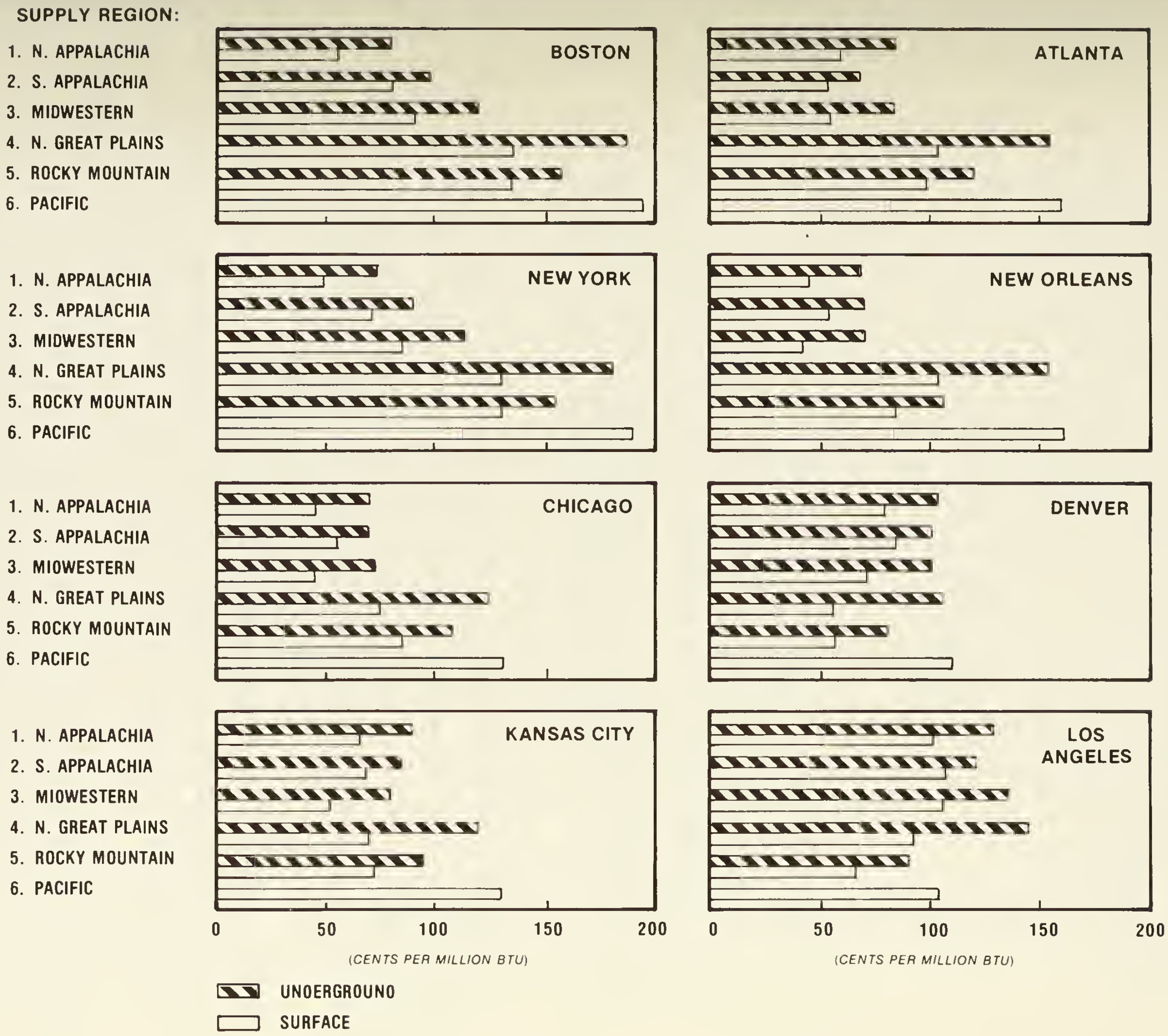


Figure 3-9. Estimated average minimum delivered coast of coal in cents per million Btu–1980* by unit train.

Table 3-8.–*Transportation costs of energy*

Form of energy transport	Cents/million Btu of primary energy/100 miles	
	Range for all references	Likely range for Western States
Slurry pipeline	1.0-5.0* 1.3-3.8†	1.0-5.0
Unit train	2.5† 3.2-600-mile length‡ 3.9-1,089-mile length‡ 2.7-4.0§	2.5-4.0
Electricity	2.8-6.4† 3.0-3.6, 700 kV a.c.* 3.6-4.8, 500 kV a.c.* 4.8-6.6, 345 kV a.c.* 6.6-9.0, 200 kV a.c.*	2.8-9.0

*The 1970 National Power Survey, Part III, Federal Power Commission, 1971.
†The Southwest Energy Study.
‡Unit Train and Volume all-rail Tariffs on Coal Shipments from Montana and Wyoming Mines, Branch of Interfuels and Special Studies, Sept., 1973.
§Burlington Northern, Inc., Tariffs, September, 1973.

However, these plants are only in the planning stage and are all subject to cancellation.

Although massive pipeline construction could expand the market area for NGP CSNG, the most probable markets will be those that can be supplied by existing pipelines. These markets are in North and South Dakota, Nebraska, Minnesota, Iowa, Montana, Wyoming, Colorado, Utah, California, Nevada, Arizona, Washington, Oregon, and Idaho.

Implicit in the acceptance of CSNG as a viable product is a belief that over the long term:

(1) Either the price of gas at the wellhead will continue to be regulated and maintained at a level which will insure shortages of natural gas (which would require supplements from other higher priced, nonregulated sources) or

(2) The price of gas will be deregulated, and would rise to (and remain at) such a level that provision of supplemental supplies (such as CSNG) would become profitable.

Without an outright shortage of gas or a substantial price increase for natural gas, CSNG could not possibly be a factor in the interstate market. To illustrate:

Prices of high Btu CSNG from western coal range from $0.91 to $1.27 MSCF

Federal Power Commission Price Ceiling on Interstate Natural Gas Sales—$0.42 MSCF

Intrastate long-term sales (unregulated) $0.90 to $1.20 MSCF

Presently, a partial deregulation—or at least a series of allowable price increases—is taking place, and general price increases are expected to continue. Most authorities expect these increases to stimulate exploration for new domestic sources of natural gas but not to compensate for predicted shortfalls in supply. For instance, the National Petroleum Council[8] predicts that U.S. gas demand will increase from 22 trillion cubic feet per year in 1970 to more than 41 trillion cubic feet per year in 1985, while maximum domestic production will be 30.6 trillion cubic feet[9] per year (under extremely favorable circumstances). This very substantial gap would have to be made up by supplementary supplies, including (potentially) Northern Great Plains synthetic gas (if the shortages occur in areas that can be reasonably served by NGP gas).

Although NGP-produced synthetic gas could conveniently serve the four markets listed above, each of these potential CSNG markets can be served by a number of competitive fuels which could conceivably threaten the NGP market share. Table 3-9 shows the competitive supplementary (i.e., not including domestic natural gas, the *primary* fuel) gaseous fuels available to each of the market areas and their estimated prices. An examination of the table shows that Alaskan/Canadian gas and Nuclear Stimulated Natural Gas (assuming the technology proves feasible) could be very price competitive with NGP CSNG in its potential market areas.

(c) *Generation and Export of Electric Power.*—A third market for NGP coal is electric power generation in the NGP. In 1971, 33.8 percent of NGP coal production was consumed in the region and 12.7 percent was exported in the form of electricity.

Power generation utilities in the region have already made their plans for expansions in capacity through the early 1980's. As the surplus generating capacity within the Northern Great Plains and the transmission capacity determines the ability of the utilities to export power, the supply potential of export power from the Northern Great Plains is essentially fixed through about 1985. The Department of the Interior has forecasted further increases in electric generation between 1982 and 2000, but utilities have generally not announced specific plant sitings beyond the early 1980's.

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[8]"U.S. Energy Outlook," National Petroleum Council, Dec. 1972.

[9]This is a much more optimistic forecast of domestic production of both NG and SNG than that made by the 1973 Interior forecast.

Table 3-9.—*Competitive supplementary gaseous fuels*
(Source: Branch of Natural Gas, Division of Fossil Fuels, USBM)

Market area	Fuel	Wholesale price $/million Btu (1972 dollars)
North and South Dakota, Nebraska, Minnesota, Iowa	CSNG* (Western)	1.10–1.27
	CSNG (Eastern)	1.24–1.40
	LNG†	1.35
	NSG‡	0.86–1.05
	North Slope** (into U.S. West)	1.37
	North Slope (into U.S. Central)	1.16
	Alberta Gas	0.97
Montana, Wyoming, Colorado, Utah	CSNG (Western)	0.91–1.08
	CSNG (Eastern)	1.34–1.50
	NSG	0.67–0.86
	North Slope (into U.S. West)	1.07
	Alberta Gas	0.67
California, Nevada, Arizona	CSNG (Western)	1.04–1.21
	CSNG (Eastern)	1.52–1.68
	LNG	1.47
	NSG	0.80–0.99
	North Slope (into U.S. West)	0.90
	Alberta Gas	0.50
	Alaska LNG	1.25
Washington, Oregon, Idaho	CSNG (Western)	0.96–1.13
	CSNG (Eastern)	1.26–1.42
	LSNG§	1.40
	LSNG	1.47
	NSG	0.73–0.92
	North Slope (into U.S. West)	0.87
	Alberta Gas	0.47
	Alaska LNG	1.22

*Coal Synthetic Natural Gas.
†Liquified Natural Gas.
‡Nuclear Stimulated Natural Gas.
**Gas from Alaskan North Slope and Canadian Mackenzie Delta.
§Liquid Synthetic Natural Gas.

Northern Great Plains coal is currently competitive in some export markets even though transportation charges are substantial. It follows that Northern Great Plains coal is in an excellent competitive position within the region. Table 3-10 reflects in-region utilities' plans for future generating capacity through 1982.[10] For South Dakota, which is close to active in-region coal mines, and the coal producing states of Montana, Wyoming, and North Dakota, almost all additions to total generating capacity will depend on subbituminous coal or lignite. Nebraska, which is located further from the coal mining area, will depend on nuclear power for most additions to capacity, but will, nevertheless, add approximately 1,850 MW of coal-burning capacity.

(d) *Market Conclusions.*–In conclusion, the time frame becomes very important when discussing the marketplace for Northern Great Plains coal energy. For the immediate future, there is a very clear and broad market for NGP coal. Coal in general–and low sulfur coal in particular–is in short supply. Spot sales of bituminous steam coal have reached 40 dollars per ton. High sulfur coal, while available, cannot be used because powerplants do not have stack gas desulfurization equipment and will not have it for several years. Thus, the high transportation costs of NGP coal may be somewhat irrelevant in many markets, especially with the price of oil so high.

The long-term market for NGP coal energy is less certain. There are certainly several factors that are distinctly favorable to optimistic market predictions. Chief among these are expectations that, without massive new development, coal demand will outstrip supply as U.S. energy demand continues to grow while alternative energy sources cannot keep up. The NGP coal would then find a large market merely because it is an available and reliable energy source. Also, although stack gas desulfurization equipment should be readily available in a few years, a continuation of the capital shortage in the electric utility industry will probably discourage installation of this capital-intensive equipment. Instead powerplants would tend to use low sulfur fuels–such as NGP coal–to meet emission requirements.

However, circumstances could be substantially different than pictured above. Although several energy companies have announced coal gasification plants for the NGP, these plans may be stimied by an influx of less expensive Canadian and Arctic gas into potential NGP markets. Given an availability of capital–perhaps provided by the Federal Government–and sufficient eastern and midwestern production, the utility industry will have the clear option of installing stack gas

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[10] 1990 for Nebraska.

Table 3-10.–*Northern Great Plains region–projected additions of electric generating capacity, 1973-1982**

Plant name and company		Capacity, megawatts (MW)	Fuel type	Scheduled operation date
NORTH DAKOTA:				
Leland Olds 2	(BEPC)	438	Lignite	10/75
Center 2	(MPCoop)	435	Lignite	5/77
Lignite 1	(CPA)	400	Lignite	11/78
Lignite 2	(CPA)	400	Lignite	11/79
Proposed	(BEPC)	500	Lignite	5/79
Proposed	(MDU)	20	Oil, gas	5/80
Proposed	(MDU)	100	Lignite	5/81
Proposed	(NSP)	800	Lignite	5/81
Proposed	(OTPC)	200	Lignite	5/81
SOUTH DAKOTA:				
Big Stone	(OTPC)	430	Lignite	5/75
Yankton 4	(NWPS)	6	Oil	1/74
Aberdeen	(NWPS)	20	Oil, gas	5/78
Mitchell	(NWPS)	20	Oil, gas	5/79
Proposed	(NWPS)	20	Oil, gas	5/80
Proposed	(NWPS)	100	Coal	5/81
MONTANA:				
Colstrip 1	(MPC)	330	Coal	7/75
Colstrip 2	(MPC)	330	Coal	7/76
Colstrip 3	(MPC)	700	Coal	7/78
Colstrip 4	(MPC)	700	Coal	7/79
Libby 1	(Army)	121	Hydro	7/75
Libby 2	(Army)	121	Hydro	10/75
Libby 3	(Army)	121	Hydro	1/76
Libby 4	(Army)	121	Hydro	4/76
Libby 5	(Army)	121	Hydro	10/82
WYOMING:				
Dave Johnston	(PPL)	330	Coal	1972
Jim Bridger 1	(IPC)	500	Coal	6/74
Jim Bridger 2	(PPL)	500	Coal	9/75
Jim Bridger 3	(PPL)	500	Coal	9/76
Wyodak	(PPL)	330	Coal	5/77

Table 3-10.–*Northern Great Plains region–projected additions of electric generating capacity, 1973-1982**–Continued

Plant name and company		Capacity, megawatts (MW)	Fuel type	Scheduled operation date
NEBRASKA:				
Hebron 1	(NPPD)	50	Gas	1973
McCook 1	(NPPD)	48	Gas	1973
Sheldon 3	(NPPD)	50	Gas	1973
Jones St. 1,2	(OPPD)	116	Gas	1973
Cooper 1	(NPPD)	778	Nuclear	1973
Ft. Calhoun 1	(OPPD)	457	Nuclear	1973
Fremont	(FDU)	80	Gas, coal	1976
Gentleman 1	(NPPD)	650	Coal	1977
Gentleman 2	(NPPD)	600	Coal	1980
Proposed	(OPPD)	100	Gas, oil	1978
Proposed	(OPPD)	200	Gas	1979
Proposed	(NPPD)	200	Gas	1980
Ft. Calhoun 2	(OPPD)	900	Nuclear	1980
Cooper 2	(NPPD)	1,100	Nuclear	1984
Ft. Calhoun 3	(OPPD)	1,100	Nuclear	1990
Otoe County	(OPPD)	600	Coal	1979

*Data from Federal Power Commission on 10-year future programmed units as furnished by utility regional reliability councils.

desulfurization equipment and burning high sulfur coals. Although the availability of slurry pipelines and high desulfurization costs for competing coals would be in its favor, NGP coal may still be at a serious price disadvantage in some key markets if the Interagency Coal Task Force's predictions are correct. Thus, truly massive coal development in the NGP—on a scale consistent with the high Coal Development Profile—will occur only if the factors controlling the markets for NGP coal develop in a way distinctly favorable to such development, and this is by no means a certainty.

3-7. *Federal and State Actions That Might Affect Development.*—The following represents a number of areas where Federal and state actions may have a substantial affect on NGP coal development:

a. *Mineral leasing policy.*—The Federal and State Governments control vast reserves of coal in the Northern Great Plains area. Any expansion or contraction of coal leases issued would affect coal production.

b. *Import policies.*—Coal is the prime energy candidate, through conversion, to make up for shortfalls of imported energy supplies such as natural gas and petroleum. By a policy of expanding or contracting import quotas, the Federal Government will affect the domestic demand for coal.

c. *Environmental quality standards.*—Any relaxation of air quality standards will cause a shift from use of NGP coal in some markets to eastern or midwestern coal to meet electric generating requirements. Stricter reclamation and rehabilitation standards for surface mining could shift preference from surface-mined coal to underground coal.

d. *Research and development support.*—Coal demand fluctuates accordingly to the availability, size, and use of research and development funds. For instance, if federally funded nuclear and solar energy programs result in technological advances, demand for coal will be reduced. If, however, funds are provided for development of coal gasification and liquefaction techniques and these techniques are developed, demand for coal will increase providing the conversion cost is competitive.

e. *State policies.*—States will also play an important role in determining the rate and extent of coal development in the Northern Great Plains. The amount of state taxes imposed on coal development facilities and on the product will influence its price and competitive position in the market place. State plant siting acts and the allocation of water resources will also

influence the level and type of coal development. As an example, Montana and North Dakota have taken action to discourage the construction of coal conversion plants on federally leased lands.

3-8. ***Method Used to Assess Range of Potential Changes.***—The 1973 Department of the Interior consumption forecast described in the previous section was used to construct a CDP (Coal Development Profile) for the Northern Great Plains. The rate of coal production, which is described in the intermediate CDP (designated CDP II), is consistent with the national energy consumption and production forecast. Coal Development Profile II represents an estimate of the NGP coal production rate for export, in-region power generation, electrical export, and synthetic natural gas production consistent with the Interior forecast. Explicitly assumed is that sulfur dioxide emission control devices will be available for installation in 1980.

Clearly, other rates of consumption are possible. Therefore, two additional CDP's were postulated: a lower rate of coal production (CDP I) sufficient to meet existing contractual agreements and increases in regional demand for coal, and a higher rate of coal production (CDP III) based on the maximum contribution that NGP coal might reasonably be expected to make in alleviating shortages in the supply of imported oil and gas and domestic nuclear electric generation.

Rates and types of consumption may be impacted by alternate land use policies. Some of the alternatives that are available are discussed in the conservation section 3-4.

(a) *Rationale for Use.*—Each CDP postulates an amount of coal that could be produced, and why; where mines, power generation, and SNG facilities could be sited; how much acreage would then be disturbed, and where; how much water would be required; and how many jobs would be created. Each CDP characterizes a development situation in sufficient detail to become the basis for analysis of impacts and issues.

In each CDP, the coal produced is used in a number of ways. These include electric generation for in-region consumption, electric generation for export, coal export, and synthetic natural gas production.

Electric generation for in-region consumption does not vary between CDP's and electric generation for export varies only in the low CDP I after 1985. The low CDP I has no synthetic natural gas production while the intermediate CDP II has synthetic natural gas production in 1985 and the high CDP III in 1980. The level of coal exports varies significantly between CDP's. This detail is summarized graphically in figure 3-10.

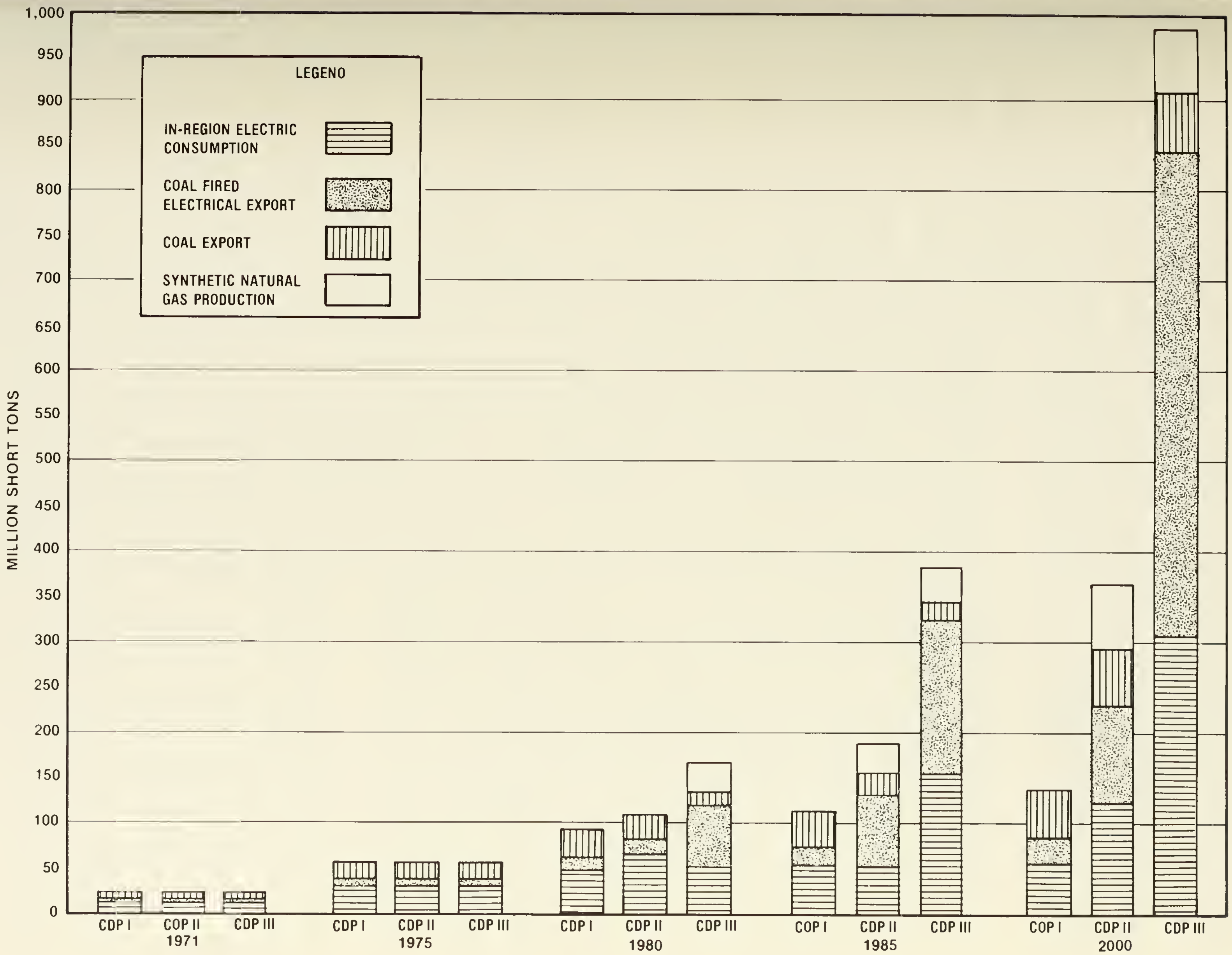

Figure 3-10. Various forms of coal use for each CDP.

The employment generated by this development plus the water and land requirements associated with each CDP are shown in table 3-11.

The low rate (CDP I) represents the minimum reasonable rate of coal production since it includes only those increases in production which are already guaranteed (that is, secured by signed long-term contracts) or highly probable (that is, supplying increased regional thermal-electric powerplants).

The higher rate CDP III is based upon the following specific assumed shortfalls below the projected levels of national energy supplies: imported petroleum—3 mbl/day (million barrels per day) in 1985, 5 mbl/day in 2000; Canadian natural gas—1,000 bcf/yr (billion cubic feet per year) in 1980, 2,100 bcf/yr in 1985, and 4,000 bcf/yr in 2000; nuclear generating capacity 20,000 MW in 1985 and 240,000 MW in 2000. The coal production estimates for this CDP are based upon significant exports to the largest conceivable market area that NGP coal might serve in order to make up a portion of this shortfall. Because of current trends toward increasing energy use and the increasing difficulty of importing energy, it is prudent to consider the possibility that this maximum rate of production of NGP coal may be necessary. This higher CDP III probably represents maximum production because of likely shortages of transportation facilities, capital, and skilled manpower in the region, and the high cost of shipping coal long distances.

This method of analysis was chosen since it provides a means for establishing realistic minimum and maximum rates of possible coal production, as well as a middle rate, and relating the resultant production levels to both the national energy situation and the impact on the region. This permits a comprehensive identification and analysis of impact. It does not establish a plan or alternative plans for coal production for the area.

(b) *Siting of Mines and Plants.*—The projection of mine sites for various CDP's was based upon coal demand, identified by states in the Northern Great Plains, as estimated by the National Energy Considerations Work Group. The Minerals Work Group first identified the geographical locations of the so-called "strippable" coal reserves in the study area. It was assumed that the optimum (or "unit") sizes of powerplants ranged from 1,025 to 1,250 MW (megawatts) and required from 3.5 to 6.8 million tons of coal per year (dependent upon the power produced and the BTU content of the coal which ranged, in the estimates, from 9,650 to 6,000 Btu/lb)[11]. It was assumed that the optimum size for a coal gasification facility was 250 MCFD (million cubic

[11] Assumes 65 x 10^{12} Btu per year from coal per 1,000 MW of electrical capacity.

Table 3-11.–*Year 2000 Northern Great Plains*

CDP	Coal* production MST	Number of gasification plants	Number of new coal-fired electric powerplants	Direct coal-related employment in principal impact areas above 1970 levels	Water consumption 1,000 acre ft/yr	Acres disturbed annually	Acres being reclaimed** at any one time	Acres used for permanent facilities
I	144	0	7	5,000	124	3,998	19,990	4,935
II	362	16	12	24,000	730	13,132	65,660	26,227
III	977	41	12	58,000	1,500	30,749	153,745	59,350

*Energy Work Group data.
**Revegetation for cropland productivity, assuming 5 years required.

feet/day) which required from 7.1 to 11.5 million tons of coal per year (based again, on a range of 9,650 to 6,000 Btu/lb)[12]. It was assumed that export mines would produce about 10 million tons per year; however, a few mines from 4 to 9 million tons per year production were sited. It was further assumed that the life of a coal natural gas conversion plant would be 20 to 35 years (powerplants 35 years). Thus, a total coal requirement for a mine was derived.

Based then on the location of mines, the indicated interest of mining companies and "conversion" companies in other sites, the general quality (BTU content) and thickness of the coal, and a cursory evaluation of coal/land ownership, mines, and therefore, mine-mouth plants were sited. First priority was given to those sites for which feasibility studies or actual construction plans had been announced. Proximity of water sources and gas pipelines was not directly considered as a constraint although proximity to drainage channels was considered. Allowances were not made for improved conversion efficiencies. Export mines were sited with some consideration of transportation routes but no consideration of specific destinations for the exported coal. In all siting projections, no special consideration was given to minimizing potential adverse social and environmental impacts.

(c) *Importance of NGP Coal by CDP* and by both tonnage and as a percentage of national energy consumption.

Table 3-12.–*NGP coal production*

(Million short tons)

CDP	1971	1975	1980	1985	2000
Low (I)	21.3	52	91	108	144
Intermediate (II)	21.3	52	107	192	362
High (III)	21.3	52	160	382	977

(Percent of national energy consumption)

CDP	1971	1975	1980	1985	2000
Low (I)	0.46	0.97	1.42	1.39	1.13
Intermediate (II)	.46	.97	1.67	2.47	2.83
High (III)	.46	.97	2.50	4.91	7.64

[12] Assumes 137.5 x 10^{12} Btu per year from coal per 250 x 106 million cubic feet per day gas output.

Table 3-12 reflects an increasing percentage contribution by NGP coal to national energy supply in the intermediate and high CDP's, but a decreasing contribution after 1980 in the low CDP[13]. The CDP's are based on national energy consumption of 191.9 quadrillion Btu's in 2000. The CEQ (Council on Environmental Quality) has established 121 quadrillion Btu's as an expected demand goal for year 2000 energy consumption. The 14.7 quadrillion Btu's which NGP coal would contribute in 2000 in the high CDP represents about one-fifth of the energy saved under the CEQ goal. If their goal is achieved, some reduction in NGP coal production is likely.

Table 3-13 gives state production detail reflecting some concentration of activity in Wyoming and Montana.

Table 3-13.–*Coal production from each NGP state for each CDP*

	(Million short tons)				
	1971	1975	1980	1985	2000
Montana					
Low (CDP I)	7.1	20	34	39	58
Intermediate (CDP II)	7.1	20	41	75	133
High (CDP III)	7.1	20	64	153	393
Wyoming					
Low (CDP I)	8.1	23	37	43	55
Intermediate (CDP II)	8.1	23	47	73	110
High (CDP III)	8.1	23	54	153	386
North Dakota					
Low (CDP I)	6.1	9	19	26	33
Intermediate (CDP II)	6.1	9	19	44	119
High (CDP III)	6.1	9	42	76	198

(d) *Current Outlook in Relation to the CDP's.*–The CDP coal extraction rates were projected in early 1973 by the Energy Work Group. Actual production plans by industry were changing substantially and have continued to change. To determine the latest industry projections, Montana, North Dakota, and Wyoming updated their data for a 1980 target date as shown on the following:

[13] For the year 2000, in the intermediate CDP, national coal consumption would be 16.4 percent of total energy consumption. In the low CDP, national coal consumption would be 16-16.4 percent of total energy consumption. In the high CDP, national coal consumption would be over 21.2 percent of total energy consumption, the exact amount depending upon the response of non-NGP coal to assumed shortages.

Production rates, 1980
(Million tons per year)

CDP I Estimate	91
CDP II Estimate	107
Actual Industry Expectation	143
CDP III Estimate	160

The actual estimate of coal production is based on contracts and the best estimates of individual companies for export, power generation, and synthetic natural gas production. It includes one 10 MT/yr (million ton per year) mine for one CSNG plant in North Dakota that is expected to be in operation by 1979-80.

The 143 MT/yr 1980 estimate is 11 percent below the CDP III estimate and 34 percent above the CDP II estimate. The CDP II was projected by the Energy Work Group in early 1973 to be the most probable production level. The 143 MT/yr current industry expectation is greater and indicates there has been more interest in developing NGP coal than anticipated. The production that actually takes place, however, could vary significantly from either the CDP estimates or actual industry expectations.

PART IV–LAND, WATER, AND AIR RESOURCES OF THE NORTHERN GREAT PLAINS

1. Land Resources

4-1. *Introduction*.–The NGP is "Big-Sky Country." Much of it is so open and rolling that in Dunn County, North Dakota, two large hills rising 600 feet above the plains are referred to as mountains. The Northern Great Plains stretch nearly 350 miles north to south–from Canada on the north to central South Dakota on the south–and almost 450 miles east and west from central North Dakota to Montana (plate 9).

In the rolling grass and brush-covered plains of the eastern part of the region, a lone tree is an outstanding feature. A low butte or a hazy mountain range in the distance is an attraction. It is a country of wind. Wind that quickly dries soils and drifts snow during the blizzardy winters. It is a dry country; only 2 percent is covered by the waters of lakes and streams. Annual precipitation normally ranges from 10 to 26 inches. Much of plains region only receives 12 to 16 inches of precipitation in a year. Thornwaite[1] said in 1941 that out of 37 years, 1 had been humid, 1 moist subhumid, 5 dry subhumid, 25 semiarid, and 5 arid. The arid and some of the semiarid years are too dry to reclaim disturbed land without irrigation.

The NGP is a land of big cattle-and-wheat ranches. Ward County, North Dakota, has the smallest average size farm, 815 acres. Natrona County, Wyoming, has the largest, 11,105 acres. Farms and ranches have to be large because it takes a great number of acres to produce enough to support a family. Seventy percent of the area is pasture and range; 26 percent is cultivated for wheat, barley, flax, rye, oats, corn, alfalfa, and sugar beets, but "wheat-and-meat" are the main products. In 1971, a little less than one-twelfth of all U.S. wheat was produced in this region, and less than 3 percent of the land is irrigated.

There are few people, only 4.4 per square mile, compared with Iowa and Ohio having 52 and 263 persons per square mile, respectively. Many have a love for the land. A frontier ethic of "stand on your own two feet" is still strong. There are Indians: the Sioux, the Northern Cheyenne, Crow, Assiniboine, Gros Ventre. The six major reservations include 5.6 million acres or 6.4 percent of the land. About 25,000 individuals live on these reservations resulting in a density of only 2.9 persons per square mile.

[1] Thornwaite, C. W., "Climate and Man" 1941 USDA Yearbook.

Even though there are relatively few people in the NGP urban land, consumption is already affecting the NGP. Between 1958 and 1967, the intensively built-up urban area increased 27 percent to 1.2 million acres.

The transportation net is the only development spread across the whole NGP. There are 5,440 miles of major electric transmission lines, 88,565 miles of rural and municipal roads, 5,000 miles of railroad lines, 7,421 miles of oil and gas pipelines, and 100 public airports.

(a) *Resources of National Importance.*—Before the coming of the white man, the Northern Great Plains were controlled by a mobile and powerful Indian people. The first white men who came to exploit their lands were the fur trappers and traders, soon after came the pioneers traversing the Oregon Trail. From the south came the cowboys herding thousands of head of longhorns. There was a time of triumph and defeat for both Indian and non-Indians alike. There was Sitting Bull and Crazy Horse and the Battle of the Little Bighorn. Open-range ranching started and then faltered in the terrible winter of 1886-87 and began again. As the cattle industry grew and the miners came to dig for gold, the Indians' hold on the land was wrested away from them and the basic culture and lifestyle that exists in the Northern Great Plains was established.

The rivers of the region are its' life lines. Along these ranches are built, crops are grown, and roads and railways laid down. Rivers are also the key to the varied and abundant wildlife, fishing, and variety in the scenery. Segments of Clark's Fork of the Yellowstone, the Yellowstone, the Missouri, and the Little Missouri are being considered for national wild, scenic, or recreation river status. The Upper Yellowstone and Sand Creek in Crook County, Wyoming, are two of this country's few remaining blue-ribbon trout streams.

Some 2.5 million acres of the 92 million acres that comprise the Northern Great Plains study area are "wild lands" some of which have potential for inclusion in the National Wilderness System. Most are already Federally owned and they depict a wide variety of topography and vegetation. Five areas are being considered for inclusion in the Wilderness System. They are portions of the Big Horn Mountains, Theodore Roosevelt National Memorial Park, Little Missouri, Charlie Russell National Wildlife Refuge, and Lost Wood-Medicine Lake Refuges. Nearly 3 million acres adjacent to the Northern Great Plains study area in the Missouri Basin may soon be proposed by Congress as "Wildnerness Areas."

The black-footed ferret, a rare predator of the prairie dog, and the whooping crane seasonally inhabit the region. Although they are possibly the best known of all the endangered species in the

United States, others are found in the NGP. The American peregrine falcon, the prairie falcon, the tule white-fronted goose, the spotted bass, the American osprey, the prairie pigeon hawk, the mountain plover, the long-billed curlew, the western burrowing owl, the northern swift fox, and the northern greater prairie chicken either stop by on annual migrations or live there throughout the year.

Big game is another resource of national significance. Before 1800, there were an estimated 700,000 antelope in South Dakota as well as millions of buffalo. Lewis and Clark first met the grizzly here and alerted the world to his existence. They called him *Ursus horribilis*, the horrible bear. Mule deer, white-tailed deer, and black bears abound, and Big Horn sheep are still found in the more inaccessible areas.

Hunting is a part of the NGP culture with many nonresidents coming into the region to take part in these activities. In 1970, there were over 90,000 nonresident hunters licensed to hunt in Montana and Wyoming.

The quality of antelope hunting is outstanding. Hunters also come for deer and elk, sheep, sage grouse, and other upland birds and waterfowl. The high quality of hunting found in the NGP is directly related to the relatively low pressure of hunting on game populations and the thousands of acres of undeveloped land.

Other kinds of recreationists visit the NGP as they move to areas on its fringes, such as Yellowstone Park or the Black Hills. The Badlands areas, for example, in Theodore Roosevelt National Park, are a unique scenic feature found mostly along river breaks.

All of these resources are of importance to many more people than just those of the region. They are national resources, and many are the last vestiges of what this country once was.

(b) *Resources of Regional Importance.*–All of the resources of the Northern Great Plains are important to the people who live there. They either create the basic productivity, from which their livelihood is derived, or they add to that complex mixture of history, attitudes, and landscape appearance that results in their life style.

The resources critical to the ranching industry are the hay meadows, irrigation water for the meadows, and the dry grazing land. In North Dakota, dryland hay production areas are also important. To the farmer, of critical importance are irrigation water and cropland areas.

The livelihood of a significant number of residents is derived from production of nonrenewable resources such as coal, gas, oil, and uranium. Without these resources and their production these peoples' livelihood is lost.

The recreation-tourism is a basic industry of the NGP. It provides an outlet for resident-recreationists as well as tourists. Of prime importance to this industry are the relatively unaltered rivers and adjoining landscape, the surrounding mountains, and the rich wildlife resources. The same resources that create the recreation-tourism industry are just as significant to the residents because they help to create the overall atmosphere. The relatively undisturbed open landscapes, clear and free-flowing rivers, and the clean air are very important.

Coal development and the associated growth in population would impact the natural resources of the NGP, and therefore the life and livelihood of the people, both of the region and visitors. The potential impacts of coal development are discussed in subsection 4-2(c).

The first aspect of coal development which will be discussed is the impact on land resources (sec. 4-2). Of special concern are the ecosystems that may be disturbed—the potential for restoration.

The second aspect of coal development which might have substantial impact is the use of water for coal conversion activities; such as electric power generation or coal gasification plants and the increased domestic use of water. Questions concerning the use of water by coal development and their impacts on surface and ground water are discussed in section entitled "Water Resources."

A third aspect of coal development is the air pollution that might result from the operation of electric generation or gasification plants and associated activities. The possible extent and impact of air pollution is addressed in the section on "Air Resources" (sec. 4-12).

4-2. *Land Resources.*—The impact of potential coal development on the land resources of the Northern Great Plains has raised issues of national as well as regional interest. The most obvious impacts on land resources will come from surface mining, however, there are many other related activities that will also impact land. Some of the issues related to this development include:

—What kinds of ecosystems are found in the Northern Great Plains and how will coal development affect them?

—How much land will coal development disturb?

—Can the land be restored after mining is completed?

—What are the long term as well as the short term losses?

(a) *Ecosystems of the NGP.*—There are six broad ecosystem catagories in the NGP area. These are individually tabulated below to provide a perspective for more detailed consideration of the areas land resources.

The ecosystem categories are:* System

	System in percent of study area	System in percent of strippable coal acreage
Grasslands	67	58
Streambottoms	4	2.1
Badlands	3.3	1.2
Brushlands	17	28
Ponderosa Pine	4	10.5
Mountains	4	0
Other	0.7	0.2

*Text combines the following ecosystems as shown on plate 7. Grasslands include: short-grass, midshort grass, midgrass, grassland sandsage, midtall grass, foothills grassland, and prairie oak savanna. Brushlands include: grassland-sagebrush and sagebrush-steppe. Mountains include: black hills pine, Douglas-fir forest, pine-Douglas fir, and subalpine. No ecosystems are combined in badlands and ponderosa pine. Flood plains are named streambottoms in text to incorporate closely associated adjoining landscape rather than just the flood plains; however, percentages shown on plate 7 refer only to the acreages in the floodplains.

Sixteen ecosystems were used in the more detailed work group analyses as shown on plate 7. These were condensed into the above six categories for ease of analysis.

(1) *Grasslands.*–Sixty-seven percent of the NGP is grassland which is underlaid by 58 percent of the strippable coal acreage. Precipitation ranges from 18 inches in central North Dakota to 10-14 inches in southeastern Montana and northeastern Wyoming.

In the wetter North Dakota area, unplowed native grass is dense and ranges from knee high to waist high. In the drier areas of southeastern Montana and northeastern Wyoming, it is a little more than ankle deep and is mostly blue grama grass and buffalo grass. Much of the knee-high grasslands of northeastern Montana and northwestern North Dakota have been plowed and converted into farms. In the short-grass areas of southeast Montana and northeast Wyoming, only about 10 percent of the land is farmed. Throughout the grasslands, if the land isn't farmed it is grazed by livestock and some wildlife.

Throughout the grassland there are also forbs (herbs) that mix the bright colors of their blossoms with the various shades of green. There are some shrubs, more as one goes from wetter to drier areas. There is big sagebrush for which the West is famous. Wildlife include antelope, jackrabbits, paririe dogs, black-footed ferrets, meadowlarks, prairie chickens, and birds of prey. Around cropland are ring-neck pheasant and red fox. The land and pothole country of northwestern North Dakota and northeastern Montana is part of the North American "duck factory." The endangered whooping crane passes through here annually.

Most of the grassland is rolling open country and because they are so rare and seen for such great distances, every hill must have a name—from Smokey Finger to Horse Nose Buttes.

Wildlife is the most important recreational resource of the grasslands. The big game, birds, and fish attract hunters, fishermen, and wildlife observers from all over the United States as well as serving as recreation (and a food source) for people of the NGP.

The grasslands are also the site of many historic attractions ranging from Custer's Battlefield to hundreds of areas where archeological remnants of Indian life are found.

Rehabilitation of most grasslands will be easier than other areas since topography is gentle and soils are fairly well developed. Rehabilitation of this ecosystem is especially important since so much mining will take place there.

(2) *Streambottoms.*—About 4 percent of the study area is in streambottoms which is underlaid by 2.1 percent of the strippable coal acreage.

The rivers, flood plains, and adjoining landscapes are "the rivers of life" for the region. Historically, and at present, most human activity radiates outward from the flood plains. Places like Billings, Bismarck, Sheridan, Rapid City, Casper, and Douglas are located in or adjoining the flood plains. Flood plains, being few in number in the NGP, are vitally important wherever they are found. They are the principal land form that breaks up the relatively monotonous adjoining open rolling country, giving it a unique character and identity. They pass through the grasslands, badlands, brushlands, and timberlands.

Typical streambottom vegetation includes cottonwood, willow, green ash, box elder, greasewood, salt grass, and western wheat grass. It is the home of furbearing animals and other wildlife such as mule deer, white-tailed deer, red fox, and numerous species of birds. Streambottoms are natural hazard areas, extremely susceptable to disruption. Stable stream banks and most of the adjoining flood-plain landscape would be nearly impossible to reconstruct. Mining in the streambottoms could disrupt the entire ecosystem for many miles upstream as well as downstream. The loss of vegetation from streambottoms would make the adjacent uplands less valuable for wildlife and domestic stock. Wildlife ranging over many miles often depends on the narrow thread of streambottom. Revegetation of the bottoms, under correct procedures, would be relatively easy because of the shallow ground water. However, great danger lies in disturbing this area because of the proximity of the flowing water and because of the dangers created from disturbing the natural flood-retarding character of the flood plain.

The streambottom ecosystem is a complicated and dynamic environment where the seemingly different aquatic and terrestrial systems join to provide an environment with a diversity not found anywhere else in the region. The purely aquatic environment and the riparian habitat are inextricably joined and this dynamic interdependence of the two environments is expressed in many ways. The plants and animals that live in the streams depend on a continuing supply of nutrients that are washed from the adjacent landscape, consequently their habitat may be severely degraded by run-off of excessive nutrients or sediment. Many insects and other invertebrates that spend their adult phases on land and are a food source for the small mammals and birds living on the flood plain, spend their juvenile phases in the stream where they are a food base for fish which in turn are preyed upon by other animals. Bushes and trees stabilize banks and provide refuge for small fish and in turn derive the moisture they require for growth and reproduction. Bacterial activity in the streams purifies the water, benefiting the many animals that rely upon it. Because of the many chemical and biological processes associated with a stream ecosystem, it is tolerant of a wide variation of conditions. However, if one system becomes inoperable it can have cascading impacts which destroy parts of, and in some cases, the entire natural community.

Coal development may change streams by increasing the TDS (total dissolved solids), BOD (biochemical oxygen demand), and temperature. Significant deviations from the normal range of any one of these factors could have deleterious effects on aquatic animals. It must be recognized that the effect of a change will depend on the total spectrum of biochemical and physical conditions existing at the time and not on one factor alone. For instance, as temperature rises, the metabolic rate of cold-blooded animals increase and their biological oxygen demand increases. Simultaneously, as temperature rises, the amount of oxygen that is naturally contained in a given volume of water is decreased so at the very time more oxygen is required, less is available. This then, exposes the animal to two stresses, one directly attributable to increased temperature, the other indirectly to reduced oxygen. As this simple example illustrates, the changes that may occur due to TDS and BOD cannot be considered separately but must be integrated before impacts can be determined. Such an integration is beyond the scope of this study and when conducted is necessarily limited to specific sites because of the complex nature of such a study and the variation between sites.

The streams in the Northern Great Plains at their headwaters are steep gradient streams characterized by low water temperatures, TDS, sediment loads, and high oxygen concentrations. Their headwaters are trout water. They are clear and support insect larvae with high oxygen demands. As the steams traverse the plains, they begin changing. Their gradient decreases and they flow slower, eventually meandering across large bits of real estate creating large flood plains. The TDS and sediment loads as well as nutrient levels increase, summer temperatures are higher, and dissolved oxygen content is reduced, sometimes to critical levels.

The aquatic species begin to change. The gravel beds become caked with sediment. Trout are unable to spawn here. The insect larvae that live here are those that tolerate lower dissolved oxygen concentrations and higher temperatures. Channel catfish and sauger become the dominant species.

If coal development results in increased water temperatures, TDS, BOD, and sediment loads, we can expect the trout and the species associated with it to retreat towards the headwaters while many of the species now living in the lower portions of the streams will invade the areas vacated by the trout.

(3) *Badlands.*–In the study area, 3.3 percent is referred to as badlands and is underlaid by 1.2 percent of the strippable coal acreage.

Badlands occur mostly along river courses: the lower Powder River where it adjoins the Yellowstone, south slopes along the upper Tongue, and in a belt 5 to 25 miles wide and over 200 miles long along the Little Missouri in North Dakota. There are large badland areas along the Missouri in the Charlie Russell National Wildlife Refuge.

Badlands get their name from the raw, bare, rapidly eroding, usually south-facing slopes of exposed layers of shale, lignite, and sandstone. In the gentler rolling parts and in pockets along deep, steep-sided coulees, a shallow soil supports plant growth, grazing, and even some small areas of dryland farms. Precipitation is only 10 to 14 inches, which makes a harsh environment even less hospitable.

Typical vegetation included shadscale, greasewood, and saltgrass on the thin soils. On better soils, big sagebrush, fringe sagebrush, rabbitbrush, bluebunch wheatgrasses, and Rocky Mountain juniper trees are common.

Wildlife includes mule deer, prairie rattlesnakes, lizards, rabbits, and a myriad of other prairie animals. Wild turkeys have been reintroduced and are doing well. In total, the badlands, like the streambottoms, are critically important to wildlife, vegetation, and recreation.

Because of the crazy-quilt mixture of raw slopes and strips, patches and flats of shallow soil, and the mixtures of reds, whites, yellows, and grays from clays, bentonites, and brick red scoria, the badlands are extremely fragile. They cannot be restored to anything near their original condition. To grow plants would probably require importing cover soil and even then so little is known about it that the results are unpredictable. To recreate the colors would take more paint than could be afforded. In any case, the stark, rare beauty of intricately woven steep-sided ridges and coulees could not be duplicated and disturbance would greately increase erosion. The badlands are likely to be an increasingly important recreation resource as interest in wilderness hiking, camping, and nature study increases.

(4) *Brushlands.*—Approximately 17 percent of the study area is brushland and is underlaid by 28 percent of the strippable coal acreage.

Part of the southernmost portion of the study area in Montana and most of northeastern Wyoming is brushland. This area receives some 10 to 14 inches of precipitation per year. The soils are generally lighter with more silty and loamy textures than in the grasslands. The grasses are much the same species as in the grasslands with some of the taller ones missing. Bluebunch wheatgrass is a major grass species. Saltgrass, shadscale, and greasewood indicate saline soils. Big sagebrush is a dominant woody species. It is an absolute necessity for sage grouse and generally so for antelope. Antelope and sage grouse are the most abundant game species in this ecosystem. Both antelope and sage grouse are nearly unique to the Northern Plains and both attract many hunters. Sage grouse are the second largest upland game bird following wild turkey. Mule deer and antelope winter ranges are located in the brushland along the foothills.

Less than 5 percent of the brushlands are in cropland and less than half the cropland is irrigated. Most of the rest of the brushlands is grazed by domestic livestock. Most of the year the land looks dry and desolate. Because so much of this type of ecosystem is open and rolling, power lines and plants would be visible for long distances. Most of the surface material over coal is saline or alkaline and needs special handling. Techniques for properly handling this material remain to be developed.

Many native plants would be useful in revegetation of strip-mined land. Because of the usually dry climate and frequency of drought, revegetation will take more effort here than in much of the grassland.

(5) *Ponderosa pine*—Four percent of the study area is ponderosa pine and is underlaid by 10.5 percent of the strippable coal acreage.

The Ponderosa pine forest is the most common and driest of the forests of the Northern Great Plains. Scattered throughout eastern Montana, northeastern Wyoming, and the western Dakotas, it receives about 12 to 17 inches of precipitation annually. Ponderosa usually occurs on the moister north slopes of steep topography, crests of hills, ridges, and rimrock.

Most of the previously mentioned grass species are found in the understory. In addition, western snowberry occurs here in quantity. It is also an important wildlife area. Mule deer are at home as well as many species of birds of prey. The pine forest is much more complicated than the brushlands or grasslands because the trees provide diverse habitats. A large share of the shallow ground water is recharged from aquifers surfacing in the ponderosa pine type.

(6) *Mountains.*–About 4 percent of the study area is mountainous and has no underlying coal seams.

These areas include the wetter pine forest of the Black Hills, Douglas firs, and the subalpine areas of the higher mountains. These receive more precipitation than any area of the Northern Great Plains, some 18 to 26 inches. The Black Hills and the Big Horn Mountains provide the principal backdrops for the Northern Great Plains region. Although they do not contain coal, they are vitally important to the region and national recreation scene. Coal development activity out on the more open country would affect these regions, as a result of human immigration, more powerplants, rights-of-way, air pollution, and possibly water diversion structures.

(b) *Rehabilitation Potential of the NGP Surface Minable Land.*–The successful rehabilitation of the ecosystem of the Northern Great Plains will depend on conditions that exist at the restoration site. Factors to be considered are precipitation, soils, topography, complexity of the premine vegetation and projected use of the lands. Central to all rehabilitation efforts is re-introduction of vegetation to the disturbed land. Important factors controlling the potential for revegetating various land types include: (1) amount and distribution of precipitation, (2) soil productivity and stability, and (3) suitability and availability of plants for rehabilitation purposes. An examination of these three factors shows that the surface minable lands of the NGP occur in 7 annual precipitation zones, 17 soil associations, and 9 broad vegetative types.

Of all possible combinations of these factors 86 occur in the Northern Great Plains, thus, the surface minable lands can be divided into 86 different kinds of land each with its own revegetation-potential characteristics. Most combinations are found in more than one location,

there are a total of 146 areas which have been denoted as rehabilitation-response units (RRU) (plate 8). It has been assumed that, regardless of location, rehabilitation response units that have the same soil-vegetation-precipitation identifications should have similar responses to rehabilitation efforts. For purposes of this study it was assumed that overburden and topographic characteristics would not constrain vegetation.

Rehabilitation research has been initiated on 15 surface coal mines and three large bentonite mines in the NGP. These mines are found on only 14 of the 86 different RRU. Fortunately they are distributed over a sufficiently varied range of RRU to allow some interpolation of results. A detailed examination of these sites plus an analysis of the rehabilitation potential of each of the 86 RRU is included in the Surface Resources Work Group Report. Plate 3 graphically presents these units and divides them into areas of poor, fair, or good potential for rehabilitation.

This study reveals that Mercer and Oliver counties in North Dakota have a much higher potential for successful rehabilitation than do those in other sample counties (sample counties shown on plate 9); soils are more productive, vegetation types more suitable, and precipitation higher than in the other sample areas. Rosebud County, Montana, has the next best potential, followed by Bighorn County, Montana and Campbell County, Wyoming. The poorest rehabilitation potential recorded for Campbell County results from a combination of poor productive soils, vegetation types that have the fewest suitable and available species and the lowest precipitation in the NGP coal province.

Although general conclusions such as those drawn above are helpful to compare differences between areas within the NGP region it must be noted that relatively little experimentation and research have been directed to the problem of rehabilitating lands being mined for coal in the NGP. Perhaps the most important single point emerging from this study is that the potential for rehabilitating surface-mined land in the NGP is extremely site-specific. The general rehabilitation potential can be judged on the basis of climatic soil and vegetation components but each site will also have its particular microclimate in terms of specific physiographic, biotic, and hydrologic components. These macrosite and microsite components, as well as the measures employed to effect revegetation inherently impose constriants on and limitations to successful rehabilitation of surface mined land in the NGP.

Although plate 3 rates lands for their rehabilitation potential, it should be understood that it refers to potentials for reestablishing vegetation and not to potentials for rehabilitating

topography and shallow aquifers to predisturbance characteristics. Areas such as the badlands, streambottoms, and adjoining breaks and much of the ponderosa ecosystems have topographic characteristics that prevent re-creation to predisturbance conditions. Also, the ratings are relative to each other only. No lands in the Northern Great Plains have been revegetated for sufficient time or with a sufficient variety of native species to determine potentials for success. Indications are, however, that the best potential for success will be in the "good" areas, somewhat less potential in the "fair" areas, and the poorest potential in the "poor" areas as shown on plate 3. Within these broad rating areas, potentials will still be site-specific, depending on slope, soil, and microclimate characteristics.

Estimates of direct onsite rehabilitation costs range from approximately $700 to $1,800 per acre, depending upon the locations and the problems encountered. The rehabilitation costs shown in table 4-1 include those of land shaping, seedbed preparation, seeding, fertilizing, soil amendments, water control on slopes, mulching, sediment control in detention basins, shrub or tree planting, topsoil replacement, and in some instances outsite irrigation facilities. The largest expenses are usually those of shaping the land and replacing topsoil. Considering the relatively great tonnages of coal that will be mined per acre in the Northern Great Plains, the cost of revegetation can be accomplished without adding more than a few cents per ton (table 4-1).

Table 4-1.–*Onsite rehabilitation costs*

Coal seam thickness ft.	At a minimum cost of $700/acre cost per ton, cents	At a maximum cost of $1,800/acre cost per ton, cents
10	4.35	11.16
30	1.45	3.72
150	0.23	0.74

This does not include the cost of water and it could be relatively high. In a drought year or period of years when only one-fourth of the average precipitation were received, 9 inches of irrigation water would need to be added to assure the minimum of 12 inches for establishing grass species. If water is available from a Federal aqueduct system, it would cost $38 to $325 per acre-foot. If each acre needed to be irrigated for one year it would add $28 to $244 per acre to the revegetation expense. If water had to be applied 2 years in succession, it would add $56 to $488 respectively. If 12 inches had to be added to assure the minimum of 16 inches required for establishing large shrub and tree species, the per acre costs for irrigation would be increased by

$38 to $325 per acre and for watering 2 years by $76 to $750 per acre. These costs would be added to the $700 to $1,800 per acre revegetation costs. Although irrigation may be needed only occasionally, the expense of the water system may have to be incurred to insure sufficient water if needed.

To better understand the problems associated with revegetation of these lands and to determine the potential of restoring surface-mined lands to biological productivity research in several areas is needed. Some of these areas are:

(1) Analysis and evaluation of chemical and physical characteristics of the existing soils of geologic overburden materials in relation to their suitability for revegetation purposes;

(2) Development of methods and techniques for creating favorable microbiological activity in surface-mine spoils;

(3) Evaluation of the physical and chemical quality of surface and subsurface runoff water from mine spoils under different rehabilitation treatments;

(4) Testing and evaluation of the comparative effects of different organic soil amendments in the revegetation of surface-mine spoils;

(5) Testing and evaluation of comparative effects of selected inorganic fertilizers in the revegetation of surface-mine spoils;

(6) Development of mechanical-chemical-vegetative techniques for rehabilitating steep, abandoned surface-mine spoils;

(7) Evaluation of the effectiveness of semiarid farming techniques known to be effective on various kinds of mine spoils;

(8) Testing and evaluation of various spoil segregations and configurations for enhancement of rehabilitation success;

(9) Development of mechanical criteria for construction of mine dumps to prevent mass slumping and to reduce surface erosion; and

(10) Plant materials development and improvement.

a. Determination of the physiological tolerances of selected plant ecotypes to various soil-water potential stresses and atmospheric evaporative-demand stresses on surface-mined spoils;

b. Determination of physiological tolerances of selected plant ecotypes to saline-alkaline stresses on various kinds of surface-mined spoils;

c. Testing and evaluating hormine-stimulated rooting characteristics of native shrubs on abandoned, over-steep mine spoils; and

d. Application of tissue-culturing techniques to develop increased tolerances of selected plant ecotypes to saline-alkaline stresses on surface-mined spoils.

(c) *Impacts of coal development on surface resources.*–

(1) *Analytical method.*–An "analytical methodology" for analyzing the impacts of projected forecasts of coal development on surface resources was developed. Components consisted of: (a) basic assumptions, (b) steps in analysis, (c) rules for analysis, and (d) quantified definition of development levels (tables 4-2 and 4-3).

Table 4-2–*Lands impacted (in acreages)*–total NGP*

CDP I

	1980	1985	2000	2020§	2035§
Mined land†	5,387	16,142	50,478	130,438	190,408
Plant facilities‡	2,694	2,694	4,935	4,935	4,935
Ancillary facilities**	–	–	44,879	44,879	44,879
Total	8,081	18,836	100,292	180,252	240,222

CDP II

	1980	1985	2000	2020§	2035§
Mined land†	5,500	19,409	100,795	364,255	561,850
Plant facilities‡	2,993	11,706	26,227	26,227	26,227
Ancillary facilities**	–	–	82,518	82,518	82,518
Total	8,493	31,115	209,540	473,000	670,595

CDP II

	1980	1985	2000	2020§	2035§
Mined land†	10,938	44,107	227,705	842,685	1,303,920
Plant facilities‡	9,200	26,040	59,330	59,330	59,330
Ancillary facilities**	–	–	109,890	109,890	109,890
Total	20,138	70,147	396,925	1,011,905	1,473,140

*Acreages occupied by urban growth not determined, acreages occupied by ancillary facilities analyzed only for CPD III, year 2000 and 2035 and assumes all facilities would remain operational through 2035.

†Acreages mined up to dates indicated.

‡Acreages occupied with plants, yards, and other facilities directly associated with plants and mines.

**Acreages occupied by railroads, highways, haul roads, transmission lines, aqueducts, and reservoirs were calculated only for CDP III at year 2000.

§Acreages for 2020-2035 are based on mines operating at year 2000 level or development.

Table 4-3.—*Acres of projected habitat losses to coal development in the study area**

CDP I

Species	Year 1980	1985	2000†
Deer, mule, and white-tail	6,370	17,061	51,359
Antelope	5,478	14,914	44,227
Other big game	167	257	527
Sage grouse	3,602	8,647	23,896
Sharp-tailed grouse	5,538	14,329	42,898
Hungarian partridge	5,116	13,287	39,270
Ring-necked pheasant	3,811	10,702	31,883
Turkey	826	1,976	5,939

CDP II

Species	Year 1980	1985	2000†
Deer, mule, and white-tail	6,141	24,346	91,523
Antelope	5,259	20,548	73,662
Other big game	167	257	527
Sage grouse	3,802	16,127	50,111
Sharp-tailed grouse	5,309	20,018	75,813
Hungarian partridge	4,887	18,974	69,784
Ring-necked pheasant	3,381	12,771	52,833
Turkey	826	1,976	10,509

CDP III

Species	Year 1980	1985	2000†
Deer, mule, and white-tail	18,507	67,732	277,255
Antelope	15,007	58,594	210,842
Other big game	167	257	2,216
Sage grouse	6,825	24,716	142,669
Sharp-tailed grouse	17,675	59,958	213,970
Hungarian partridge	15,907	54,836	177,795
Ring-necked pheasant	13,016	43,177	122,638
Turkey	5,809	17,103	83,208

*Includes only good and medium quality habitat lost, except other big game and turkey also include low quality habitat.

†Acreages stripmined between 1972-1975 are considered restored and have been subtracted from year 2000 totals.

It was recognized at the outset that only subjective analyses were possible. Nevertheless, by employing a uniform and systematic approach, using matrix forms on which "affected factors," and degree and magnitude of disturbance were recorded, reasonably accurate approximations of impacts could be determined.

Sample areas selected for intensive analyses included:

Campbell County, Wyoming

Big Horn County, Montana

Rosebud County, Montana

Mercer County, North Dakota

Oliver County, North Dakota

Considering Mercer and Oliver Counties as a single area, the local areas represent four sample areas where intensive mining developments were projected. Collectively, these four sample areas represented 89 percent of coal production in CDP I for year 2000; 61 percent of the CDP II; and 61 percent of the CDP III. Thus, by far a majority of regional coal development is represented in the four sample areas.

Certain basic assumptions were prerequisite to the analyses. These were developed with the provision that additional ones as needed for particular resource considerations could be developed.

Some of the basic assumptions follow:

1. All mined lands will, as a minimum, be returned to current vegetal cover and use as nearly as possible.

2. Mined areas will have soil and overburden replaced in same sequence as present within 1 year following mining.

3. Existing laws, regulations, and requirements will remain constant and in effect during the projection period (year 2000).

4. Plant sites, reservoirs, transmission corridors, roads, towns, etc. will remain in place during all time frames through the projection period.

5. Coal seam depths vary according to the particular formations where mines were sited.

6. Assume the following acreages to be relegated to uses indicated for the duration of the projection period, dating from the time frame of establishment or operation:

Gasification plant site . . . . 1,000 acres

Gasification plant reservoir . . . . 30 acres

Power generation plant . . . . 100 acres

Power generation reservoir . . . . 50 acres

Mine facility acreages

Capacity less than 5 million tons per year . . . . 149 acres

Capacity, 5 to 10 million tons per year . . . . 150 acres

Capacity more than 10 million tons per year . . . . 153 acres

7. No additional acreage allowed for either cleaning plant or tailings pond, if required.

8. An acre foot of coal (80 percent efficiency in recovery) yields 1,416 tons.

9. Assume the following conditions for mined lands:

Campbell County, Wyoming. Mining disturbance will affect only productive rangeland. Assume 4 acres per Animal Unit Month grazing. No cropland and no forest will be affected.

Big Horn County, Montana. Mining disturbance will affect land resources thusly:

Rangeland, 80 percent; forest land, 10 percent; cropland, 10 percent, divided equally between wheat and alfalfa.

Rosebud County, Montana. Mining disturbance will affect land resources thusly:

Rangeland, 80 percent; forest land, 15 percent; and cropland, 5 percent.

Mercer and Oliver Counties, North Dakota. Best estimate available for probable land resource disturbance is:

Mercer County: 55 percent rangeland; 45 percent cropland.

Oliver County: 70 percent rangeland; 30 percent cropland.

Assume for purpose of analysis, combining both counties:

60 percent rangeland; 40 percent cropland. Assume cropland affected thusly: one-half wheat, one-fourth oats, one-fourth alfalfa hay.

12. Assume 17,000 acre feet of water requirement for a gasification plant and 15,000 acre feet for a wet-tower cooling electric power generator.

13. Assume 5 years as time requirement to return mined acreage to stable productive cropland. Assume 5 years to regenerate, by planting, forest land. Assume 10 years to return rangeland to stable and productive grazing condition. For such uses as wildlife habitat, assume a minimum of 25 years. It should be noted that these estimates are only an educated

guess, and that no field studies that would substantiate these guesses have been conducted in the NGP.

(2) *Summary of surface area to be disturbed.*—As previously discussed, there are several activities associated with coal development that remove land from use for agricultural, wildlife, and recreation purposes. These include the mine pit, haul roads, storage and loading facilities, plant facilities, and storage reservoirs. In the operation of a mine, only portions of the area actually being mined can be returned to other productive uses during the life of the mine. The acreages committed to mining activities in the four sample areas are shown in tables 4-4, 4-5, 4-6, and 4-7. The cumulative acreage of land that has been mined and that land occupied by related facilities are shown for the periods 1980, 1985, and 2000 as gross acreage. The net acreage is the number of acres that have been committed to mines and related facility uses minus the land that would be rehabilitated to grazing or cropland levels of productivity. Acreages committed to such uses as railroads, highways, haul roads, transmission lines, aqueducts, reservoirs, and urban development are not shown. These uses may equal or exceed the acreage shown in tables 4-4, 4-5, 4-6, and 4-7. The acreage committed to coal development activities including railroads, highways, transmission lines, aqueducts, and reservoirs for the total Northern Great Plains region is shown in table 4-2.

(3) *Assessment of impacts.*—

Soils.—The unique set of biotic, chemical, and physical properties constituting a given soil-plant system will be destroyed by surface mining. Soil structure will be altered; some soil micro-organisms will be lost; chemical properties will be changed; and water balances will be altered. The potential for erosion by wind and water will be increased to some unknown degree.

Those soils overlying lands not mined but used to support other associated facilities will be altered to some unknown degree. Assuming erosion is controlled and these soils are not contaminated with foreign materials they should be easier to revegetate than mined land.

The fate of trace elements and other substances emitted from coal conversion plants has not been adequately studied and hence no estimate of their impact on soils and on the micro and macro organisms associated with them can be made.

Basic to all regional planning efforts is an understanding and inventory of the basic resources of the region, certainly one of the primary needs is for detailed soil surveys that

Table 4-4.–*Campbell County land area distrubed by mining and coal conversion facilities*

CDP I

Acreage	1980	1985	2000
Mines	448	2,032	8,126
Facilities	599	599	1,047
Gross	1,047	2,631	9,173
Rehabilitated		50	4,404
Net	1,047	2,581	4,769

CDP II

Acreage	1980	1985	2000
Mines	509	2,543	12,670
Facilities	749	2,229	2,528
Gross	1,258	4,772	15,198
Rehabilitated		65	5,984
Net	1,258	4,707	9,214

CDP III

Acreage	1980	1985	2000
Mines	509	3,511	27,665
Facilities	749	6,069	9,650
Gross	1,258	9,570	37,315
Rehabilitated		90	14,000
Net	1,258	9,480	23,315

Table 4-5.—*Bighorn County land area distrubed by mining and coal conversion facilities*

CDP I

Acreage	1980	1985	2000
Mines	325	1,269	4,931
Facilities	300	300	1,050
Gross	625	1,569	5,981
Rehabilitated		37	2,525
Net	625	1,532	3,456

CDP II

Acreage	1980	1985	2000
Mines	375	1,712	9,212
Facilities	450	2,812	4,587
Gross	825	4,524	13,799
Rehabilitated		44	4,256
Net	825	4,480	9,543

CDP III

Acreage	1980	1985	2000
Mines	469	2,375	14,875
Facilities	1,631	4,144	12,719
Gross	2,100	6,519	27,594
Rehabilitated		56	6,587
Net	2,100	6,463	21,007

Table 4-6.—*Rosebud County land area disturbed by mining and coal conversion facilities*

CDP I

Acreage	1980	1985	2000
Mines	2,256	4,894	14,912
Facilities	300	300	600
Gross	**2,556**	**5,194**	**15,512**
Rehabilitated		156	8,387
Net	**2,556**	**5,038**	**7,125**

CDP II

Acreage	1980	1985	2000
Mines	2,256	5,425	23,437
Facilities	300	1,631	3,262
Gross	**2,556**	**7,056**	**26,699**
Rehabilitated		175	11,600
Net	**2,556**	**6,881**	**15,099**

CDP III

Acreage	1980	1985	2000
Mines	2,537	7,862	45,169
Facilities	1,481	5,325	6,069
Gross	**4,018**	**13,187**	**51,238**
Rehabilitated		250	20,550
Net	**4,018**	**12,937**	**30,678**

Table 4-7.–*Oliver and Mercer Counties land area disturbed by mining and coal conversion facilities*

CDP I

Acreage	1980	1985	2000
Mines	3,283	6,000	16,600
Facilities	600	600	900
Gross	3,883	6,600	17,500
Rehabilitated		1,250	10,783
Net	3,883	5,350	6,717

CDP II

Acreage	1980	1985	2000
Mines	3,283	6,708	28,333
Facilities	600	1,775	3,558
Gross	3,883	8,484	31,891
Rehabilitated		1,333	15,250
Net	3,883	7,150	16,651

CDP III

Acreage	1980	1985	2000
Mines	2,537	7,862	45,169
Facilities	1,481	5,325	6,069
Gross	4,018	13,187	51,238
Rehabilitated		250	20,550
Net	4,018	12,937	30,688

provide basic information concerning agricultural potential of soils, wildlife habitat potentials, and rehabilitational potential.

Vegetation.–Surface mining and associated plant and facilitating structures will destroy existing vegetation. Its restoration will require extensive rehabilitation measures. The resource needs related to rehabilitation are discussed in Rehabilitation Potential (section 4-2(b)) of the NGP Surface Mineable Lands. Additional needs are surveys of specie composition density and productivity at a level of detail that would describe those conditions that must be obtained by rehabilitation measures. Assuming rehabilitation technology is available, sources for seeds and plants suitable for rehabilitation needs must be developed.

As with soils, the impact of coal conversion emissions particularly trace elements and SO_2 are poorly understood and further study is needed.

Agriculture.–A more detailed examination of the impact of coal development on the agricultural economy is found in section 5-5.

Wildlife.–The adverse impacts of coal development on the wildlife resources of the NGP will be associated with the direct loss of habitat (table 4-2) resulting from mining and associated activities and urban development and the disturbances caused by human activities. Intolerant species may abandon an area that can provide their physical needs (food, water, and shelter) when human activity interferes with certain behavioral activities necessary to their survival. Assessment of the impact of coal development activities on wildlife resources is compounded by the fact that animals occupy different habitat at different times of the year and in some cases the day. For this reason the destruction of land in one area may obviate the use of land in another even though it has not been disturbed. The classical example is the general shortage of winter deer range.

Throughout the west there is an abundance of land that provides suitable habitat for deer during the spring, summer, and fall periods. These ranges are not utilized because the winter range is not sufficient to support the same population levels that could be supported by the other ranges. The winter range is therefor the factor that limits the deer population.

If coal development occurs in habitat types that are presently the factor limiting the growth of a particular wildlife population, it will reduce that population in that area as well as all other areas occupied by that population. Unfortunately, an assessment of such impacts

is not possible because of a general lack of knowledge about the wildlife of the NGP and their requirements.

The evaluation of the impact of coal development presented here is primarily the result of subjective analysis by persons who are familiar with NGP wildlife populations and their trends. An objective assessment will require detailed studies of population dynamics, behavioral characteristics, and ecological relationships of NGP wildlife.

Within these limitations the following conclusions warrant considerations.

CDP I

In the CDP I, by 1980 more than 8,000 acres of land will be occupied or physically disturbed by coal development in the NGPRP study area. The human population will increase by about 14 percent over that of 1970. Except for some species, which are threatened or endangered and for some local wildlife populations, effects on fish and wildlife habitat in the region will be minor.

In the CDP I, by 1985 some 17,000 acres will be lost to development and the population will increase by 31,000, or 8 percent over the 1970 level. The increased population may cause an additional decrease in the habitat of the peregrine falcon, since the spring and fall migration habitat of this bird encompasses most of the northern prairie, and more people will occupy that habitat. There will be slight but important decreases in ring-necked pheasant and wild turkey habitat.

Hunting pressure for elk will increase both in the study area and to the west. Applications for moose, bighorn sheep, and mountain goat hunting permits will increase slightly. Hunting pressure on sage grouse and on ring-necked pheasant in the western part of the study area will increase so that the average hunter's success will noticeably decrease.

By the year 2000, development will have occupied more than 100,000 acres and 74,000 more people will reside in the area than did in 1970. It is probable that the peregrine falcon will no longer nest in Montana or Wyoming by that time, and spring and fall migrants will be reduced to a very rare visitor.

The endangered black-footed ferret and the western burrowing owl (status undetermined) are dependent on the black-tailed prairie dog. Coal development may cause significant decreases in the number of prairie dog towns, adversely affecting the ferret and owl.

Inexpliciably, some people shoot hawks. The ferruginous hawk, prairie pigeon hawk, and prairie falcon are status-undetermined species resident in the study area. The projected human population increase by the year 2000 causes serious concern for these birds of prey.

Losses of game animal habitats will affect the wild turkey the most but sage grouse and ring-necked pheasants will lose significant habitat areas. Although only 5,900 acres of turkey habitat will be destroyed, the losses will occur in some of the better habitat areas. The sage grouse has experienced significant habitat losses recently because of large-scale sagebrush eradication programs. Under this forecast, an additional 24,000 acres of good and medium quality habitat will be lost. In view of trends, this is significant. In the region, better sagebrush habitat exists north and southwest of most development.

Also, in view of present trends, the loss of an additional 5,800 acres of good and medium quality ring-necked pheasant habitat assumes significance, particularly to the west of the Dakotas.

Regionally, most hunting will be moderately changed by the year 2000. There will be an estimated 13,000 more deer hunters, 3,300 more antelope hunters, and 7,600 more hunters seeking other big-game species.

In both North Dakota and South Dakota nonresidents are allowed to hunt big game; however, the percentage of nonresident hunters is very low. Increases in the number of resident hunters in those states will result in decreasing opportunities to hunt deer and antelope.

Locally, popular fishing sites will become overcrowded, but regionally fishing demand will not exceed the supply.

CDP II

By 1980, the CDP II development will have covered or disturbed 8,500 acres. The population of the area will increase by 61,000 over that of 1970.

Regionally, little besides raptorial habitat will be significantly affected. Deer hunting in North Dakota will have noticeably changed–mainly by increased access difficulty and decreased hunting. Hunting for other big game will have changed slightly in that elk hunting conditions will be more restricted and opportunities to hunt other species will be reduced. Of upland game hunting, only sage grouse and ring-necked pheasant hunting will be regionally affected–by a few less birds, shorter seasons, and for pheasants, more restricted access to hunting areas.

By 1985, more than 31,000 acres of land will have been disturbed, destroyed, or occupied. The area's population will increase by 135,000–a 36 percent increase over 1970. The population increase is twice that of CDP I in the year 2000, but the land disturbance related to coal development is only one-third that projected for the year 2000, CDP I. It is believed human population increases will have greater impacts on fish and wildlife than will land disturbance attributable directly to coal development. For this year, then, approximately twice the impacts on fish and wildlife resources will occur as projected for the CDP I, year 2000. One mitigating factor is that the impacts would have 15 fewer years to be realized; for some species and hunting situations, such as sage grouse hunting, that may be significant.

By the year 2000, CDP II, the area's human population will have swelled by 100 percent or 376,000 more people than in 1970. More than 209,000 acres will be committed to coal development. Adverse impacts on wildlife resources and on hunting will be significant.

Because of the magnitude of change, the extirpation of the peregrine falcon in the study area, both as a summer nester and as a spring and fall migrant is predicted along with significant reductions in population levels of all raptors.

By year 2000, enough better habitat of white-tailed and muledeer, sage grouse, ring-necked pheasant, and wild turkey will have been destroyed to cause serious concern among game managers and to be readily noticed by the outdoor public. Hunting for all big-game species and some upland game (sage and sharp-tailed grouse, pheasant, turkey) will be seriously degraded.

Significant decreases in success ratios for deer, elk, and antelope will adversely affect the nonresident guiding and outfitting industry. Nonresidents traveling long distances would rather drive a little farther to areas where chances for harvesting game were better.

CDP III

Regional impacts in 1980 under the CDP III are generally comparable to impacts in 1985 under the CDP II.

By the year 2000 in the CDP III, the area's population will increase by 497,000 or 132 percent. Coal development will have destroyed almost 400,000 acres of wildlife habitat. The following impacts are projected:

1. Some 277,000 acres of good and medium quality deer habitat will be lost—almost 69,000 more deer hunters will compete with the current number of hunters for less deer.

2. Hunting for elk in Montana and Wyoming will be significantly degraded by loss of habitat and the addition of over 29,000 more resident elk hunters.

3. Sage grouse hunting has had a long-term trend in the region toward longer seasons and more liberal conditions. This trend will be abruptly reversed and by the year 2000 sage grouse hunting will be far more restricted.

4. Over 83,000 acres of turkey habitat will be destroyed. Turkey populations will be significantly reduced. However, a harvestable surplus will be available annually and turkey hunting will continue, although under far more restricted circumstances than at present.

5. Raptors will loose 295,000 acres of hunting grounds and will be subject to intentional and unintentional persecution by 497,000 more people. Impacts on resident and wintering raptors will be significant; impacts on migrating raptors are speculative.

6. Local populations of passerine birds will be eliminated. Effects on many species will be long term because it is unrealistic to project restoration of disturbed lands to natural levels of plant variety within a short time frame. Currently, the relationships of the hundreds of passerine species to the several ecosystems of the area is little understood by game biologists and land managers. The relationships probably serve a more important role in the prairie ecosystems than is widely appreciated.

7. Local populations of some endangered or threatened species will likely be extirpated. Any loss of individuals of these species would be disastrous. Candidates for losses include: American peregrine falcon, black-footed ferret, prairie falcon, prairie pigeon hawk, western burrowing owl, mountain plover, northern long-billed curlew, and ferruginous hawk.

Wilderness-wild lands.—Actual mining operations will have little effect on the inventoried wilderness-wild land resource. All impacts on existing areas of the wilderness system will be caused indirectly by increased use or possible water modifications or developments. Increased use will result in some loss of opportunities for solitude within the wildernesses. Visitors seeking solitude may have to penetrate further or pick seasons when use is light.

No proposed units to the National Wilderness Preservation System are directly affected by the projected mining operations. Any impacts will likely result from increased use or projects affecting waterflows from these areas.

Scenery.–Analysis of impacts on scenery is limited to the four sample areas. It was determined that an impact analysis on a regional basis was impracticable. There is also a major problem of attempting to compare qualities among entirely different types of scenery, that is, the scattered pines on hills near Colstrip, Montana, versus the Knife River Valley in North Dakota.

Development of power and gasification plants and anticipated smoke plumes would have the greatest impact on scenic views. In Big Horn County, Montana, except for possible plume impact, the degree of impact is considered low.

2. Water Resources

4-3. *Introduction.*–The conversion of coal to electricity or synthetic gas in the Northern Great Plains is intricately linked to water supplies. Without sufficient water at a reasonable price, coal conversion may be restrained. High water costs may affect the rate of coal development and water diversions for coal development may have to compete with existing uses and their future growth. In addition to water depletions, upstream users will discharge effluents that may affect the quality of water for downstream users.

These are but a few of the interrelationships between energy development and water. Listed below are the principal water issues concerning the Northern Great Plains. To resolve these issues is impossible. However, to highlight and discuss them is the principal purpose of this section.

–What are the existing water resources in the NGP and, how are they being used?

–What will the future demands on these resources be?

–How much water is available for energy development?

–What will water cost?

–What will be the impacts of increased water used for energy resource development?

4-4. *Historic Background.*–Water has played an important role in the development of the semiarid Northern Great Plains. Early exploration and settlements followed the river networks which comprise the Missouri River Basin. With the invention of the windmill, a greater dispersion of the settlements was allowed by insuring the farmer a convenient water supply for his household and a herd of livestock.

Just as the land resources of the Northern Great Plains are utilized to near capacity for grazing and farming activities, so also are the available water resources. Overriding other factors in the pattern of water supply and use is the very wide fluctuation in flows from season to season and from wet year to dry. Many significant rivers dry up for long stretches during drought years. Even in normal years, a high percentage of the total flow occurs during late spring. On the downstream eastern edge of the Northern Great Plains and at a few scattered sites within the region, water is impounded to insure more reliable supplies. However, the Yellowstone River and all of its tributaries, with the exception of the Bighorn, are largely unregulated and undisturbed by impoundments.

As water is a commodity of considerable value, a system of laws has evolved to determine who has the right to water. Water laws based on both the appropriation rights doctrine and the riparian rights doctrine have been adopted by the Northern Great Plains states.

The *common-law doctrine of riparian rights* is based primarily on the ownership of land and uses of water thereon contiguous to the stream. Under the Riparian Rights Doctrine, the owner of land contiguous to a natural stream or natural lake may use the waters for such purposes and in such quantities as he chooses, as long as he does not appreciably diminish the flow or impair the quality of water for downstream users. Such rights are not expressed in specific quantities of water unless they have been apportioned by the court. There is no priority of right although domestic use and the watering of domestic livestock are generally considered preferrential uses. Riparian rights are not usually transferable to land not contiguous to the stream or lake from which the water is being drawn.

Under the *appropriation rights doctrine* the beneficial use (as defined by each state) of water is the basis, the measure, and the limit of the water right. The first beneficial appropriation is prior in right. Appropriations are for a definite rate of diversion or storage and often the quantity is specified. The appropriation right is obtained and sustained only by actual and continuous beneficial use. Failure to make beneficial use of an appropriation may result in its loss. Appropriated water may be used either on land contiguous to or a distance from the water source.

4-5. ***Surface Waterflow Conditions.***—A number of rivers and basins in the Northern Great Plains region were and are being studied to determine reliable flow condition information:

(a) *Yellowstone River Basin, Montana, and Wyoming.*—The highest stream flow rates in the Yellowstone River Basin (fig. 4-1) occur in May and June and are produced by snowmelt and rainfall in the mountainous areas. The average flows that occur during this period are 5 to 10 times the average flows that occur in fall and winter months. Critically low flows, sometimes approaching no flows in some tributaries and streams, occasionally occur in the fall period causing serious water use problems for irrigators and adversely affecting fish and wildlife resources. Significantly less water is available during these drought conditions, than shown in figure 4-1. For example, the lowest recorded average June flow in the Tongue River at Miles City, Montana, is 5,997 acre-feet as compared with the historic average of 115,644 acre-feet. The Bighorn River is the only major stream in the Yellowstone Basin that is regulated. This is accomplished by controlled storage in Yellowtail and Boysen Reservoirs which are primarily

operated for power generation, flood control, and irrigation purposes. Monthly average flow releases are shown in figure 4-2.

(b) *Western Dakota Tributaries of the Upper Missouri River.*—Unlike the Yellowstone Basin, the western Dakota tributaries of the upper Missouri River are relatively short and do not drain mountainous areas. Earlier snowmelt (than in the high elevations of the Yellowstone watershed) in this plains region causes relatively high flows as early as March and April in the Little Missouri, Knife, Heart, and Cannonball Rivers (fig. 4-3). Overall, the flows in these rivers are substantially less than in the Yellowstone Basin and drought periods, intensified by the small watershed area, seriously constrain water use and productivity of aquatic resources.

(c) *Main Stem Missouri River.*—The Missouri River flows are not subject to much seasonal variation as they are regulated at Fort Peck, Garrison, and Oahe Dams for purposes such as electric power generation, flood control, and downstream navigation. Monthly average flows released from Garrison are shown in figure 4-4.

The shortage of water during years with low amounts of precipitation promoted the development of the large water impoundments for water storage in the Northern Great Plains referred to above. (Boysen, Yellowtail, Fort Peck, Garrison (Lake Sakakawea), and Oahe.) The purpose of these reservoirs is to help assure necessary water supplies to users along the Bighorn, Yellowstone, and Missouri Rivers. Demand for water can, however, still exceed streamflow and storage releases in selected tributaries, and in many years they become completely dewatered for some period (table 4-8).

4-6. *Current Trends and Uses.*—Irrigation consumes a major portion of water in the Northern Great Plains region. In the Yellowstone River Basin of Montana and Wyoming it is estimated that about 1.25 million acres of farmland are under irrigation. A total of approximately 2.26 million acres are irrigated above Lake Sakakawea in the Missouri and Yellowstone River Basins. The planned Garrison and Oahe irrigation projects, if completed, would irrigate approximately 1-1/2 million acres in the Dakotas and utilized about 3.5 million acre-feet of water from Lakes Sakakawea and Oahe.

Loss of water through evaporation from large reservoirs exceeds all other consumptive uses combined (fig. 4-5). Practices such as contouring, terracing and erosion control, and small impoundments for fisheries, recreation, stock watering, and small irrigation projects are also shown to be significant water consumers.

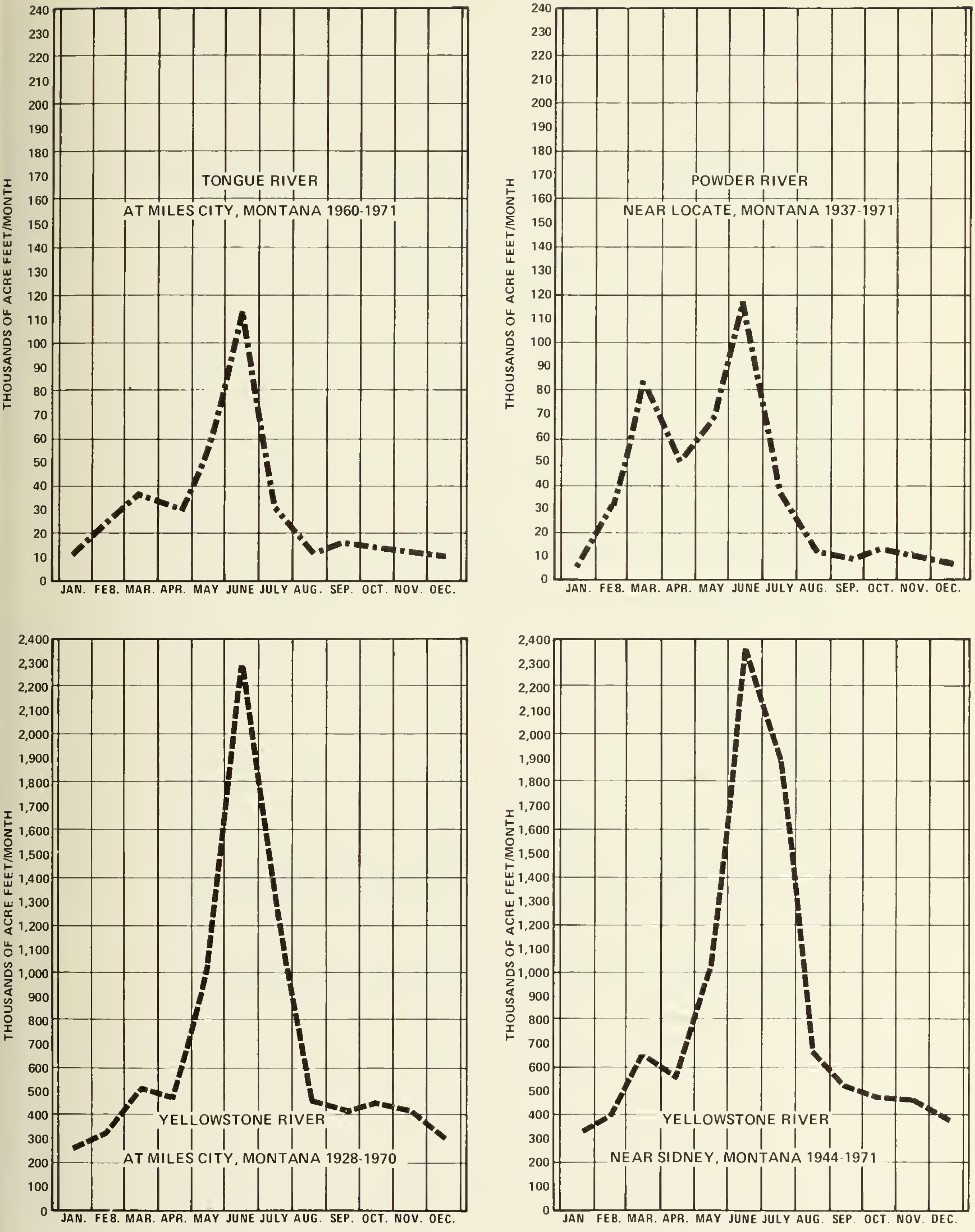

Figure 4-1. Historic Yellowstone River Basin flows.

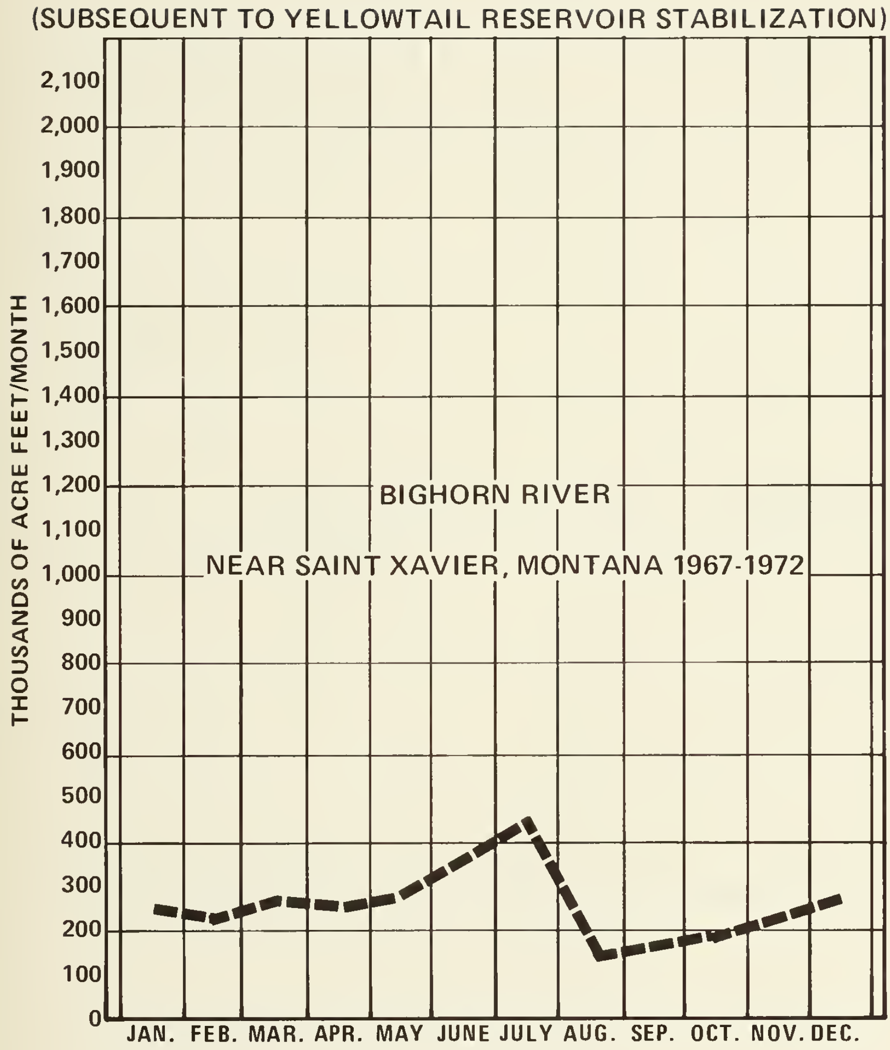

Figure 4-2. Releases from Yellowtail Dam.

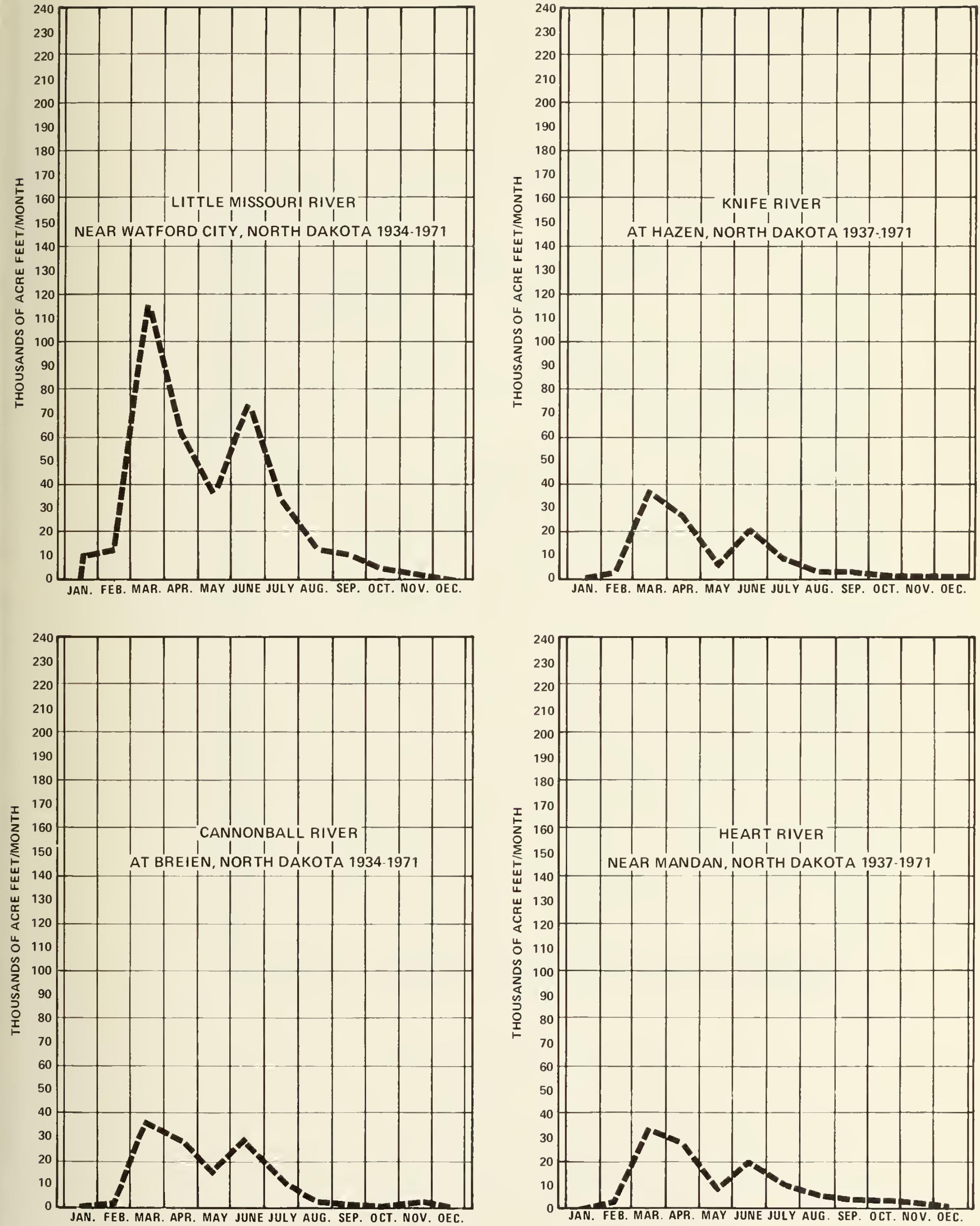

Figure 4-3. Historic western North Dakota riverflows.

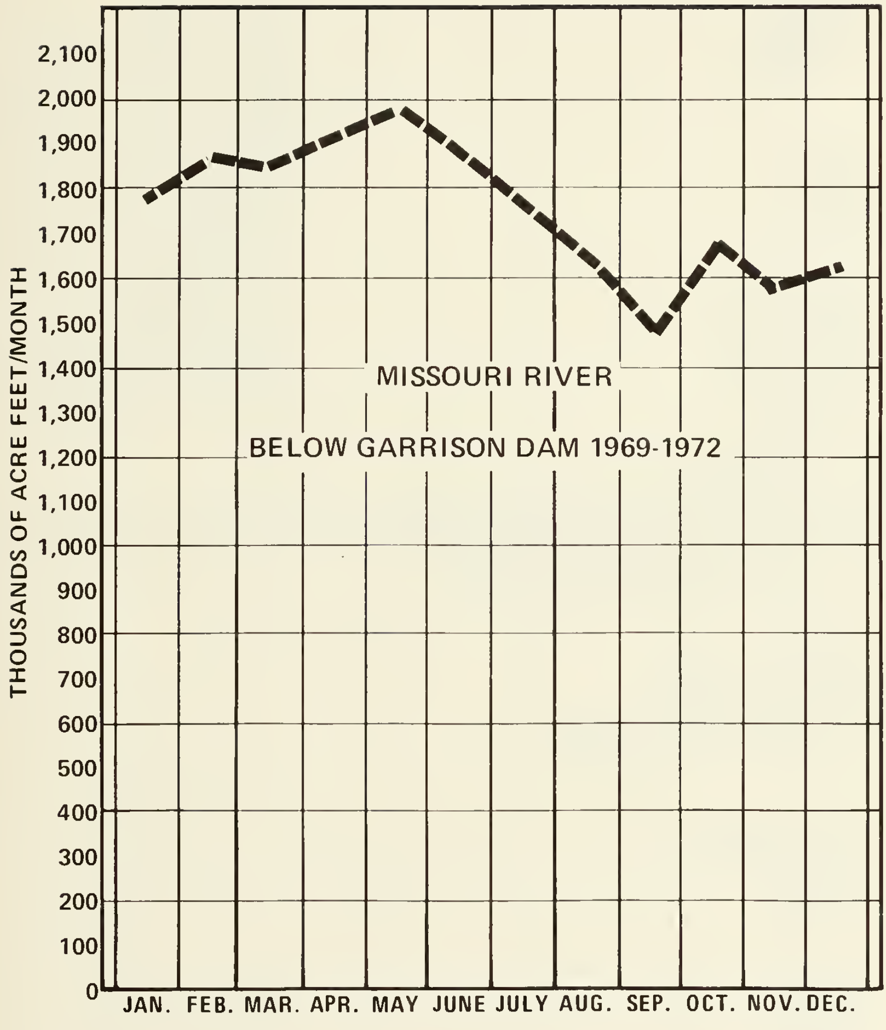

Figure 4-4. Releases from Garrison Dam.

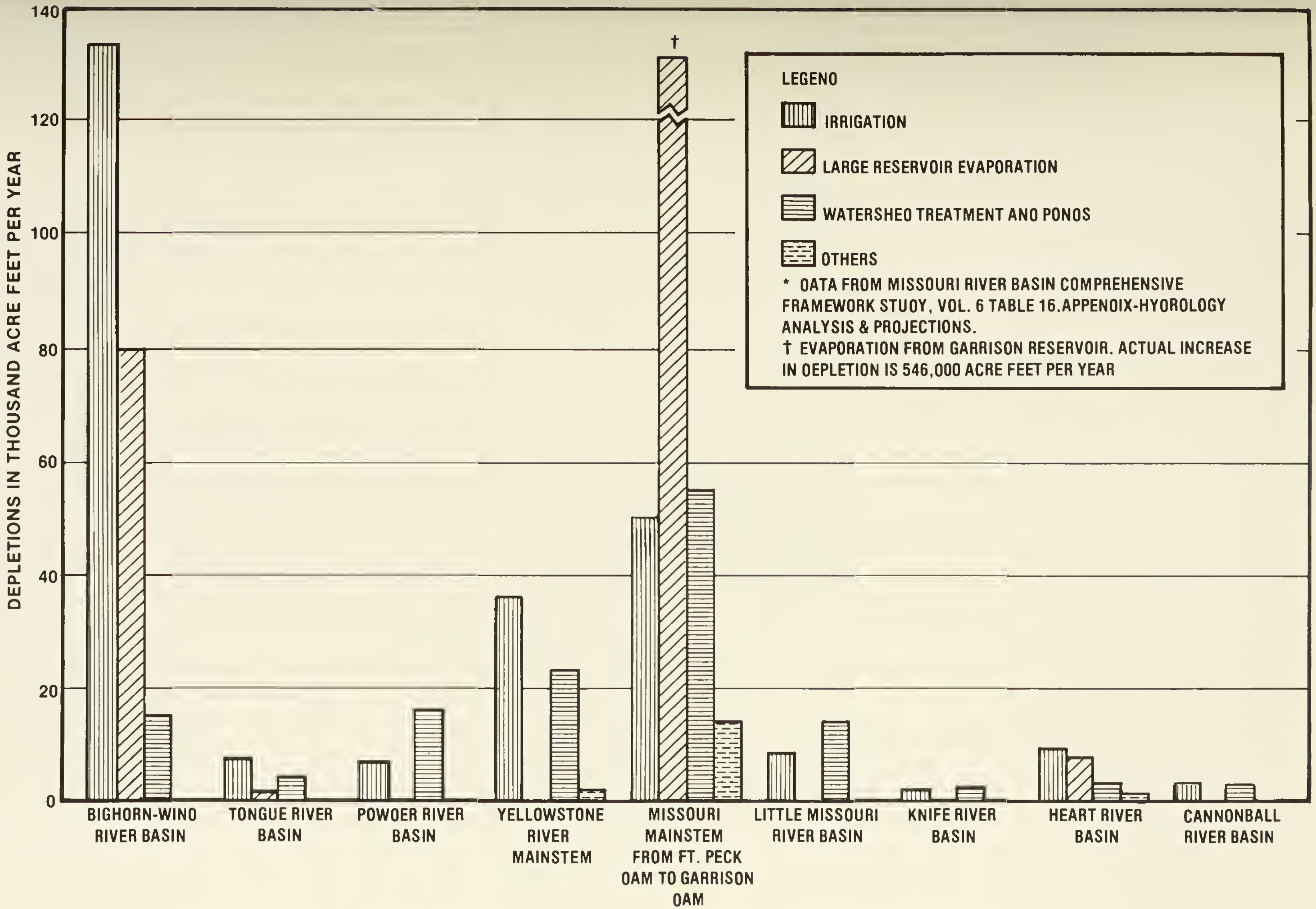

Figure 4-5. Increase in annual average depletion from 1949 to 1970*.

Table 4-8.—*Days for which flows of less than 0.1 ft^3/s were recorded in the Yellowstone and Western Dakota tributaries*

River location	Period of record	Less than 0.1 ft^3/s flow recorded: Average number of days of occurrence in a year	Less than 0.1 ft^3/s flow recorded: Annual percent occurrence
Tongue River at Miles City, Montana	1961-1970	*0.0	0
Powder River near Locate, Montana	1939-1971	1.6	0.4
Little Missouri River near Watford City, North Dakota	1935-1971	34.7	9
Knife River at Hazen, North Dakota	1930-1971	2.7	0.7
Heart River near Mandan, North Dakota	1929-1971	16.4	4
Cannonball River at Breien, North Dakota	1935-1971	22.3	6

*Zero flow recorded for July 9-19, Aug. 13, 14, and Sept. 28, 1940.

In addition to consumptive water use, there are many nonconsumptive uses such as hydroelectric power generation, navigation, fish and wildlife, recreation, and aesthetics. Some of these, such as hydropower and navigation, do not consume water. However, they sometimes require impoundment which causes a water loss through evaporation. All of these uses require that a stream cannot be completely depleted of water and as such, require allocation of the available water similar to that required by the previously discussed consumptive uses.

Approximately 87 percent, or 2,048 megawatts, of the hydropower capacity which is in the study area, or affected by it, is installed at the six main stem dams on the Missouri River: Fort Peck in Montana, Garrison in North Dakota, and Oahe, Big Bend, Fort Randall, and Gavins Point in South Dakota. Total hydropower capacity in the Yellowstone Basin is 296 megawatts, 250 megawatts of which are at Yellowtail Dam on the Bighorn River.

There is no major commercial navigation in the Missouri Basin above Sioux City, Iowa; however, downstream barge-tow transportation of farm products depends upon water stored behind the Missouri main stem dams. Indications are that under present conditions a rate of flow of 25,000 to 31,000 cubic feet per second (18 to 23 million acre-feet per year) would be adequate to support a 9-foot navigation channel downstream of Sioux City with nominal dredging.

The thrust of new development is currently shifting water use from agriculture to industry. (It is possible that this situation will change dramatically or be compounded by the need for increased food production.) Indications of this shift are the Federal Industrial Water Option Contracts and applications for stored water in the NGP.

Since 1967, option contracts to purchase Federally owned storage water have been made or are pending with many companies. An option contract is bought for a relatively nominal charge by the purchaser and will reserve, for a certain period, water in storage for future use. Additional applications for contracts to purchase Federally owned storage water have been received but are not yet in effect. Table 4-9 summarized this information for both existing and nonexistent (Moorhead Reservoir, New Tongue River Reservoir, and Yellowstone River) storage sites. It should be noted that these data indicate potential future water use involving a degree of uncertainty for the companies and, as such, is speculation similar to that of buying land underlaid with coal.

The shift away from the use of water for new irrigation is primarily the result of the new standards for Federally funded water projects for which discount rates are now 5-7/8 percent. Under the new standards and at the current discount rate, essentially no new Federally funded irrigation projects are economically justifiable. There will undoubtedly be some private and state-assisted irrigation in the future, and projects presently under construction may be expected to continue.

4-7. ***Water Demand***.—(a) *Water for Coal Conversion*.—To conduct water-supply studies for coal development and assess the impacts of such water development, assumptions pertaining to the quantity of water used at powerplants and gasification plants were necessary. The original assumptions were:

(1) Powerplants require 19,000 acre-feet of water per 1,000 MW generated, and

(2) Gasification plants producing 250 million standard cubic feet per day require 30,000 AF[2].

These assumptions were made early in 1973. Since then, new information has been developed indicating these figures to be too high. The issue is discussed below and the revised estimates of water needs are presented; however, all of the water supply studies and impact assessments were based on the *original assumptions*.

[2] Goldman, E. and Kelleher, P., Water Reuse in Fossil Fueled Power Stations. In: Complete Water Reuse, Cecil, L. K. (ed.), New York, N.Y., American Institute of Chemical Engineers, April 1973, p. 240-249.

Table 4-9.—*Federal industrial water option contracts and applications as of December 1973*

Water source*	Water options contracts in effect or pending ac-ft per year	Water option contract applications ac-ft per year
Boysen Reservoir, Wind River, Wyoming	85,000	59,000
Yellowtail Reservoir Bighorn River, Montana	623,000	630,000
Tongue River Reservoir Tongue River, Montana	4,175	0
Moorhead Reservoir (potential) Powder River, Montana	0	220,000
Fort Peck Reservoir** Missouri River, Montana	0	310,000
Lake Sakakawea** Missouri River, North Dakota	0	124,000
Lake Tschida Heart River, North Dakota	0	18,000
Yellowstone River, Montana	0	630,000
Totals in Upper Missouri Basin	712,175	1,991,000

*Water Work Group Report.
**Main stem storage.

A typical water-cooled 1,000 MW coal-fired powerplant in the NGP will utilize water for a variety of processes. The majority of the water will be used for evaporative cooling. This process will utilize around 10,000 to 12,000 acre-feet per year. Anywhere from 700-3,000 acre-feet will be consumed for ash handling depending on the methods used. If a wet SO_2 scrubber is used, it will consume about 3,000 acre-feet per year. There are other incidental water needs but they are minor compared to the above uses. The total water requirement for a 1,000-megawatt plant ranges between 12,000 and 15,000 acre-feet per year. The lower figure represents a plant that does not utilize a wet SO_2 scrubber.

Dry cooling systems, which use air instead of water, may significantly reduce the need for water. It is difficult to estimate the water needs for a 1,000 MW plant because only one dry cooling plant has been built in the NGP and it is less than 30 MW (construction of a 330 MW dry-cooled plant is being started at the same location). However, water usage estimates range from 500 to 5,000 acre-feet per year for a 1,000 MW plant. Though dry cooling conserves water, its capital and operating costs are significantly higher than for wet cooling. Only where the cost of water is substantial is dry cooling economically preferable to wet cooling. One recent study

indicates that when delivered water costs are more than about $200/AF—acre-feet; dry cooling then becomes more economical than wet cooling. For CDP I, the delivered cost of water is less than $200 per acre-foot for all of the six powerplant sites. In CDP II, those powerplants sited more than 100 miles from the point of diversion may find that dry cooling is more economical. In CDP III, water costs are slightly lower because of economies of scale; thus, dry cooling becomes economic somewhere beyond around 150 miles from the diversion point. If ground water could be combined with a wet-cooling process, this would probably be more economical than dry cooling.

Water is also necessary for the production of synthetic natural gas from coal. Precise quantification of water demand is difficult, as there are no coal gasification plants operating in the United States and the final quantification of the water demand revolves around a technology yet to be developed. Nevertheless, estimates of water needs have been made, for the *Lurgi* process, by process developers and plant designers.

The two most critical uses for water in coal gasification are as a source of hydrogen in the gasification reaction and for process steam. One study has shown that as a hydrogen source, the minimum water requirement was about 4,000 acre-feet per year for a 250-million scf/day (standard-cubic-feet-per-day) plant.[3] Additional studies have stated the lower limit to be 2,300 acre-feet per year.[4] There are significant cooling requirements associated with coal gasification as well as numerous miscellaneous water uses similar to a powerplant. Estimates of total water required for a 250-million scf/day plant have ranged as high as 30,000 acre-feet per year[5] when total evaporative cooling is used.

Utilizing the design plans of those few gasification plants proposed to be built in the United States for estimating plant water requirement, the range can be narrowed from 8,000 to 12,000 acre-feet per year. This assumes both wet- and dry-cooling systems for the various plant systems. A better understanding of the Lurgi process on western coals, coupled with moderate advances in technology, may further lower this requirement to a range of 6,000-10,000 acre-feet per year. Currently, a "best estimate" for the NGP would appear to be 9,500 acre-feet per year for a 250-million scf/day plant. If significant additional water is used, discharges would result.

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[3] Office of Coal Research, Annual Report, 1973, pp. 31-34.

[4] Washburn, Charles, "Environmental Impact of Large Scale Coal Gasification Development" a report prepared for the EPA, Ecological Studies and Technology Assessment Branch, August 1972.

[5] Final Report of the Supply-Technical Advisory Task Force—Synthetic Gas—Coal; prepared for the National Gas Survey of the Federal Power Commission; April 1973.

Table 4-10 shows a comparison of regional water requirements for various use alternatives and the levels of coal development assumed in each CDP.

Table 4-10.—*Comparison of potential water use estimates for each CDP during years 1980, 1985, and 2000*

	Megawatts MW	Synthetic natural gas (SNG) plants	High water use estimate,* acre-feet per year	Conservation water use estimate,‡ acre-feet per year	Low water use estimate,** acre-feet per year
Year 1980					
CDP I	0	0	0	0	0
CDP II	0	0	0	0	0
CDP III	0	7	210,000	66,500	42,000
Year 1985					
CDP I	0	0	0	0	0
CDP II	0	7	210,000	66,500	42,000
CDP III	0	20	600,000	190,000	120,000
Year 2000					
CDP I	6,500	0	123,500	78,000	32,500
CDP II	12,800	16	723,200	305,600	160,000
CDP III	12,800	41	1,473,200	543,000	310,000

*Assumes 30,000 af/y for a gasification plant and 19,000 af/y for 1,000 MW of electricity.
‡Assumes 9,500 af/y for a gasification plant and 12,000 af/y for 1,000 MW of electricity.
**Assumes 6,000 af/y for a gasification plant and 5,000 af/y (dry cooling) for 1,000 MW of electricity.

(b) *Water for Municipal and Domestic Use.*—Utilizing NGPRP estimates for increases in population resulting from development of new coal mines, powerplants, gasification plants, and associated growth, an estimate of municipal water needs can be developed as shown in table 4-11. The estimated water needs are based on an assumed municipal water requirement of 125-gallons-per-person per day. The range in municipal water requirements is generally between 100 (Gillette, Wyoming) and 200 (Billings, Montana; Bismark, North Dakota) gallons-per-person per day. It should be noted that as population increases per capita water consumption increases.

(c) *Water for Revegetation of Mined Lands.*—Revegetation of strip mined lands may also require water for irrigation particularly during drought conditions. Although revegetation may be

Table 4-11.—*Estimated additional municipal water needs for the region*

	Projected population increase	Million gallons per day	Acre-feet per year
CDP I	74,000	9.25	10,300
CDP II	237,000	29.63	33,100
CDP III	497,000	62.13	69,300

accomplished without irrigation when rainfall amounts are adequate, water will have to be allocated for revegetation for possible drought occurence. Assuming that the minimum annual precipitation requirement is 12 inches (the average rainfall in some areas) and that 2 consecutive years of normal precipitation is required for revegetation of grasses, and that drought conditions may provide only 4 inches of precipitation, an estimate of the supplemental revegetation water requirement can be made. By year 2000, the high level of coal development (CDP III) will require an estimated revegetation of 30,750 acres every year. Assuming that at least 2 consecutive years are needed for establishment of grasses, in a drought year, 61,500 acres would require irrigation. Therefore, 8 inches (12 in.-4 in.) of irrigation over this land area would require annually 41,200 acre-feet. Table 4-12 summarizes this water requirement for the other coal development profiles. A mine disturbing approximately 700 acres per year (assume a thin coal seam) would need 950 acre-feet while a single mine disturbing 100 acres per year (assume a thick coal seam) would need only 135 acre-feet per year. Although this amount of water probably would not be used every year (less water would be needed when rainfall exceeded 4 inches), it is obvious that a system to supply water to mine sites for use in revegetation during drought conditions will be needed along with the appropriate water rights.

As this use of water will correspond to drought conditions when water may be in short supply for competing uses, storage of water at or available to the mine site for revegetation purposes may be necessary. If the "revegetation" water rights are "junior," then revegetation efforts could severely suffer.

(d) *Water for Slurry Pipeline Export.*—Slurry pipeline export of coal also represents a potential water use. Although there is some uncertainty about the water requirements for this use, data from the slurry pipeline currently being planned for the Gillette area, indicates that the annual water requirement will be 600 to 800 acre-feet per million tons of coal transported. Using this water requirement, table 4-13 shows the amounts of water required for slurry pipeline transport of half or all mined coal projected for export.

Table 4-12.—*Water requirement for revegetation, year 2000*

	Acres being mined acres/year	Area undergoing revegetation acres/year	Supplemental irrigation requirement acre-feet/ year
CDP I	4,000	8,000	5,300
CDP II	13,200	26,400	17,700
CDP III	30,750	61,500	41,200

Table 4-13.—*Water requirements for slurry pipeline export of coal, year 2000**

	Coal exported million tons	Water need when all coal is exported by slurry pipeline acre-feet/year	Water need when one-half coal is exported by slurry pipeline, acre-feet/year
CDP I	88	61,600	30,800
CDP II	110	77,000	38,500
CDP III	534	373,800	186,900

*Calculations of water required based on 700 acre-feet per million tons of coal transported.

(e) *Total Potential Water Demand.*—A perspective of the potential total water requirement for the region for the year 2000 can be gained by combining the various water demands discussed previously with those projected by the MRBC (Missouri River Basin Commission) for agriculture for the Missouri Basin above the confluence of the Missouri and Yellowstone, and Yellowstone Basin and the Western Dakota tributaries. Not included are the depletions which may result from development of the Garrison and Oahe projects. Initial phases of these two irrigation projects are estimated to require 871,000 acre-feet and 599,900 acre-feet, respectively. Ultimate phase requirements would equal 3,500,000 acre-feet.

Assuming institutional requirements or water costs promote some conservation of water by coal conversion plants, then the conservation water use estimates given in table 4-10 give the most likely estimates of the power and gasification plants water requirements. By adding these industrial plant water needs to projected municipal, revegetation, and slurry pipeline water needs, an estimate of the total water requirements for coal development in the region can be determined as shown in table 4-15.

Table 4-14.—*MRBC* projected surface water demands for year 2000*

Water demand	Upper Missouri Basin (above Lake Sakakawea)	Yellowstone Basin	Western Dakota tributaries	Total
	All in thousands of acre-feet per year			
Cropland irrigation:				
Full service	512.2	683.6	455.0	1,650.8
Supplemental	116.0	102.5	0	218.5
Livestock	24.2	23.7	26.0	73.9
Evaporation:				
Large reservoir	20	21.7	28.0	69.7
Small reservoir	17.7	37.3	143.0	198.0
Ponds	14.8	35.2	10.0	60.0
Total	704.9	904.0	662.0	2,270.9

*MRBC Comp Fram Study, vol 6, Hydrologic Analysis and Projections Appendix, tables 23, 24, and 25, pp. 130-131, Dec. 1971.

Table 4-15.—*Coal development related water depletions for 2000 (estimates in acre-feet)*

Coal conversion (CDP III)	543,000
Municipal (CDP III)	69,300
Revegetation (CDP III)	41,200
Slurry pipeline (CDP III)*	186,900
Total	800,400

*Assumes 50 percent of exported coal shipped by slurry pipeline.

4-8. *Water Availability*.—In exploring the methods of supplying water to the various levels of coal development activities theorized in each CDP, it was assumed that flows would not be depleted to a point that would threaten the aquatic and aesthetic values associated with NGP streams. In developing the hypothetical water supply system, this constraint was applied in all cases except for parts of the Bighorn and Yellowstone Rivers in CDP III. The flows needed to maintain these values are referred to in this report as "suggested stream flows."

In discussing the subject of water availability, the region can be arbitrarily divided into three areas; (1) the Yellowstone River Basin, (2) the main stem Missouri upstream from Oahe Reservoir, and (3) the Western Dakota tributaries.

(a) *Yellowstone River Basin.*–The Yellowstone River and its tributaries are largely free-flowing, unregulated streams. The major exception is the Wind-Bighorn River which has impoundments. Two of these reservoirs, Boysen and Yellowtail Reservoirs have a combined storage capacity of 1,918,000 acre-feet. These reservoirs contain the major portion of the surface water that could be made available for coal development in the Yellowstone River Basin. In addition to this existing source of water, the potential of supplying water from three hypothetical reservoirs was studied. These included two reservoirs, the New Tongue Reservoir on the Tongue River and the Moorhead Reservoir on the Powder River to supply some CDP I requirements; and one reservoir, Pumpkin Creek, to supply some CDP II requirements. Table 4-16 shows the amount of water that was determined to be available at particular points of diversion and the water requirements for the various CDP's.

The amounts of water shown as available on table 4-16 are what would have been available annually during the driest period of record without any shortages occurring. As the table illustrates, the water requirements generated by the CDP I and II levels of coal development could be met by providing a modest amount of new storage. However, the water requirements generated by the CDP III level of development could not be met without depleting flows to a level below that necessary to maintain intrinsic stream values unless the conservation water use estimates are assumed. Under these conservation water use assumptions, new reservoirs would not be required and there would also be an additional 174,500 acre-feet of water available for diversion from the Bighorn River at Hardin. This amount of water would exceed that required by the attendant municipal and domestic requirements and the irrigation needs associated with revegetation of disturbed lands.

Although it can be concluded that there is sufficient surface water in the Yellowstone Basin to supply the needs of coal development up to the year 2000, it must be recognized that other water demands, particularly those for new irrigation supplies, will compete for this water. Therefore, the Yellowstone Basin should be considered an area where available stored water is scarce.

It has been estimated that there is up to 3 million acre-feet of water in the Upper Missouri River Basin[7] that could be made available for use without conflict with existing and developing uses. Through the construction of major reservoirs on the Yellowstone River and its tributaries, possibly 2,000,000 acre-feet of this water could be stored and made available for use in the

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[7] The Upper Missouri River Basin includes all the area that drains into the Missouri River above Souix City, Iowa.

Table 4-16.—*Water availability in the Yellowstone Basin*

Reservoir	Point of diversion	CDP I			CDP II			CDP III		
		Water available providing suggested stream-flows	Water diverted		Water available providing suggested stream-flows	Water diverted		Water available providing suggested stream-flows	Water diverted	
			High water use estimate	Conserva-tion‡ use estimate		High water use estimate	Conserva-tion‡ use estimate		High water use estimate	Conserva-tions‡ use estimate
Yellowtail and Boysen Reservoir	At Hardin and Bighorn River	353,000	–	–	`353,000	182,000	76,500	353,000	801,500	278,500
Yellowtail and Boysen Reservoir	Yellowstone River at Armells Cr.	474,000	–	–	*292,000	139,500	50,000	–	–	–
New Tongue Reservoir	Tongue River at reservoir	63,000	58,000	36,100	63,000	–	–	63,000	–	–
Moorhead Reservoir	Powder River at reservoir	77,000	23,000	14,400	77,000	–	–	77,000	–	–
Pumpkin Reservoir	Powder River at reservoir	32,000	–	–	32,000	30,000	9,500	32,000	–	–

*Amount available is 474,000 acre-feet minus the 182,000 acre-feet diverted from the Bighorn River at Hardin.

‡Based on supplying a 250,000,000 cu. ft. per day gasification plant with 9,500 acre-feet per year and supplying a 1,000 megawatt generating plant with 12,000 acre-feet per year.

Yellowstone Basin. Any amount used in the Yellowstone Basin would of course not be available for use downstream. The environmental impact of such storage reservoirs is unknown, but it is believed by many to be unacceptable.

(b) *Western Dakota Tributaries.*—The Western Dakota tributaries, even with new storage, can provide only minimal amounts of water when compared to the Yellowstone Basin or the main stem Missouri. Table 4-17 lists the potential reservoir sites on selected tributaries and the amounts of water that could be made available from them. It should be noted that the storage capacities required are very high compared to the amount of water that would be available on an annual basis. The environmental impact of building these reservoirs is unknown. However, it is believed to be one of the least acceptable water supply alternatives considered.

(c) *Main stem Missouri River.*—Unlike the Yellowstone Basin, the Missouri River main stem has an abundance of stored water, some of which may be made available for coal development purposes. Three large reservoirs, Ft. Peck, Sakakawea, and Oahe have a total storage capacity of 66,600,000 acre-feet (table 4-18).

The average annual flow at Oahe, the dam furthest downstream, is 18,525,000 acre-feet. Of this amount, at least 3 million acre-feet could be made available for coal development without competing with existing or anticipated uses. Diversions of water from these reservoirs in the amounts studied would have relatively little impact on the existing aquatic habitat when compared to diversions in the Yellowstone Basin.

Figure 4-6 shows the amount of water that would be diverted from Lake Sakakawea in the year 2000 to supply the various CDP's.

(d) *Deep Ground Water.*—Recent studies have indicated a potential for development of deep ground-water supplies from the Madison Group, a deeply buried limestone aquifer. These rocks underlie the entire Powder River Basin of Montana and Wyoming and are exposed on the flanks of the surrounding mountains.

Much of the Madison formation and underlying carbonates contain water of fair to moderate water quality (total solids 1,000-2,000 milligrams per liter). Because of the cost of drilling wells and the presence of high sodium concentrations in most of the water analyzed, the use of these deep ground-water supplies for irrigation is questionable. In general, the water does not meet the U.S. Public Health Service Standards (1962) for use on interstate carriers, but it is used for municipal water supply in several towns of the region, including Midwest, Newcastle, Upton, and Osage. With treatment, this water would be suitable for industrial uses.

Table 4-17.—*Water available from Western Dakota tributaries*

River basin	Reservoir site	Total storage capacity (acre-feet)	Water available providing suggested instream flows (acre-feet per year)
Little Missouri	Marmarth	504,000	26,000
	Medora	332,000	54,000
	Wagon Creek	230,000	25,000
	Beaver	89,000	2,000
	Mill Iron	45,000	5,000
Knife	Broncho	305,000	17,000
Heart	–	–	Negligible
Cannonball	Mott	230,000	13,000
	Thunderhawk	216,000	12,000
	Cannonball	172,000	22,000
Moreau	Bixby	253,000	23,000

*Diversion from reservoir in all cases.

Table 4-18.—*Main stem Missouri River storage capacity*

Dam	Reservoir	State	Capacity in acre-feet		Average annual flow (acre-feet)
			Total	Holdover	
Ft. Peck	Ft. Peck	Montana	18,900,000	10,900,000	6,838,000
Garrison	Lake Sakakawea	North Dakota	24,200,000	13,400,000	16,952,000
Oahe	Lake Oahe	South Dakota	23,500,000	13,700,000	18,525,000

Major ground-water development from the Madison Group should it occur, would to a considerable extent, consist of mining a resource because use may exceed recharge. If wells are put down near the center of the basin, where most of the strippable coal occurs, major water development will probably not have any significant effect on recharge areas for many years. As mining of the water from the Madison occurs, the artesian head will decline, pump lifts will continue to increase, and the cone of influence of the well field will enlarge. As an example, in the Midwest, Wyoming area, major water development from the Madison formation has been under way since 1917 when the Tisdale well (T. 41N, R. 81W., Sec. 16), yielding more than 4,000 gpm (gallons per minute) was completed. A total of 14 wells have been drilled in this area to supply water for the oil industry. The deepest well is 10,040 feet and its original yield was 810 gallons per minute. Yields of wells in this area initially ranged from 430 gallons per minute to more than 9,000 gallons per minute. Available data show seven wells averaging 3,800 gallons per minute.

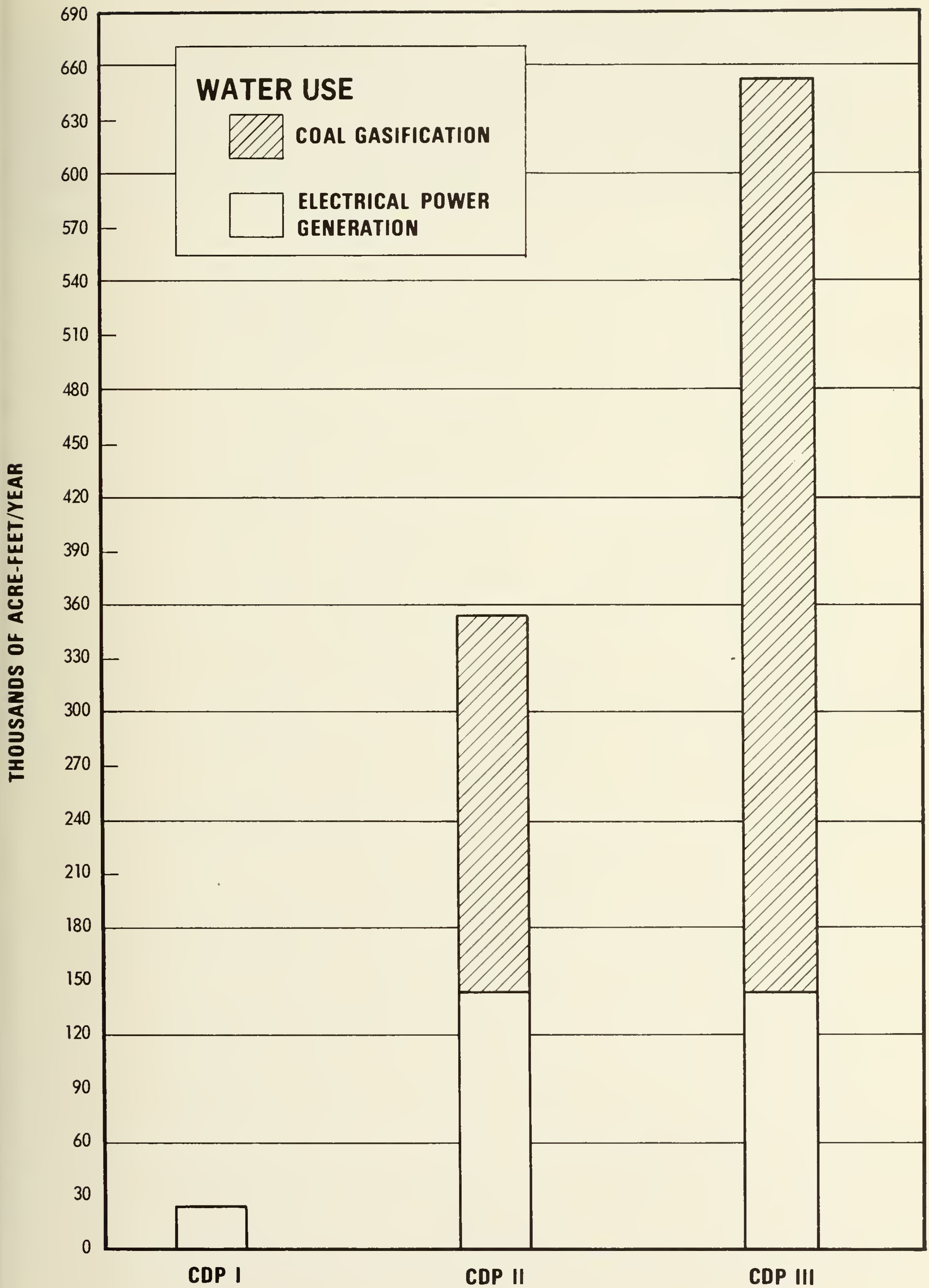


Figure 4-6. Water diverted from Lake Sakakawea for coal conversion facilities in North Dakota–Year 2000.

A word of caution is necessary with respect to this source of water for coal conversion use. Substantial study should be undertaken prior to development to assess the effects that mining the Madison aquifer will have on shallow ground-water supplies, ground-water recharge capability, and hence, domestic water supplies. Of particular concern is the continued availability of adequate supplies of water for both municipal and agricultural use in the Black Hills (South Dakota) region.

4-9. *Water Costs.*—(a) *Surface Water.*—The main variables affecting the cost of surface water are: (1) whether water can be taken without constructing a new reservoir (either from an existing reservoir or a diversion without storage); (2) the distance the water must be conveyed by aqueduct; (3) the amount of pumping required; and (4) the total amount of water moved through the pipeline—since economies of scale may result in lower cost for larger aqueducts.

On the average, surface water for the North Dakota plant sites will be less expensive than surface water supplied to the Montana or Wyoming sites (table 4-19). Since Lake Sakakawea is an existing water source, new impoundments are not necessary. Less pumping will be required due to the terrain of the land in North Dakota and the shorter distance from the lakes to the sites.

Table 4-19.—*Water supply systems costs by CDP.**

	Water supplied thousands of acre-feet	Total* capital costs $ millions	Range of cost dollars per acre-foot	Average costs dollars per acre-foot
CDP I (Mont./Wyo.)	101	50	63-115	82
(N. Dak.)	23	7	38	38
CDP II (Mont./Wyo.)	371	503	47-310	147
(N. Dak.)	354	286	35-222	90
CDP III (Mont./Wyo.)	802	1,105	47-378	147
(N. Dak.)	686	444	40-199	77

*All cost data for choice No. 1 for each CDP as analyzed by Water Work Group.

In North Dakota, as more water is supplied, the average cost per acre-foot declines. Most of the plant sites in either CDP II or CDP III are clustered together. Thus, capital costs or pipeline mileage increases very little. In Montana and Wyoming, the additional plant sites in CDP III are much farther away from possible diversions and may require more pumping; consequently, capital costs increase substantially with the quantity of water supplied.

Table 4-20 shows the costs of supplying water to the various powerplants and gasification plants in the three CDP's. The two choices shown are based on alternate aqueduct systems.

(b) *Ground Water.*—The supply systems developed for each CDP consider only surface water as a possible water source; however, ground water has been discussed as a possible alternative. There are four variables which affect the cost of ground water from the Madison: (1) the depth

Table 4-20.–*Summary of water costs of CDP's per acre-foot*

Plant* No.	Quantity of water delivered acre-feet/ year	CDP I		CDP II		CDP III	
		Choice 1	Choice 2	Choice 1	Choice 2	Choice 1	Choice 2
P-1	13,000	$115	$325	$230	$ 89	$189	$234
P-2	19,500	63	193	144	183	146	143
P-3	19,500	74	209	165	162	168	127
P-4	19,500	48	257	167	121	179	97
P-5	19,500	80	296	80	296	80	80
P-6	23,000	38	38	89	54	64	26
P-7	23,000			222	95	199	192
P-8	23,000			175	124	152	144
P-9	23,000			102	152	95	173
P-10	23,000			140	104	116	78
P-11	23,000			198	216	182	184
G-1	30,000			176	275	378	203
G-2				310	133	268	328
G-3				210	66	238	290
G-4				118	199	224	274
G-5				93	268	206	253
G-6				124	126	206	253
G-7				74	70	195	277
G-8				47	43	189	271
G-9				151	134	161	243
G-10				50	52	133	152
G-11				50	52	133	152
G-12				50	52	92	298
G-13				53	79	47	84
G-14				47	88	47	84
G-15				35	28	47	84
G-16				35	26	47	84
G-17						118	88

Table 4-20.–*Summary of water costs of CDP's per acre-foot*–Continued

Plant* No.	Quantity of water delivered acre-feet/ year	CDP 1		CDP II		CDP III	
		Choice 1	Choice 2	Choice 1	Choice 2	Choice 1	Choice 2
G-18						97	68
G-19						76	47
G-20						76	47
G-21						76	47
G-22						105	76
G-23						154	95
G-24						154	95
G-25						109	133
G-26						49	76
G-27						49	76
G-28						49	76
G-29						49	76
G-30						49	76
G-31						49	76
G-32						49	76
G-33						49	47
G-34						49	47
G-35						40	66
G-36						40	66
G-37						51	49
G-38						54	29
G-39						80	32
G-40						80	32
G-41						80	32
G-42	30,000					135	128

*P denotes powerplants and G denotes gasification plants. Numbers correspond to the facilities shown on plate B-4 for CDP I, plate B-5 for CDP II, and plate B-6 for CDP III.

of the aquifer, (2) the depth below the surface to which the water will rise under artesian pressure, (3) feasible withdrawal rates, and (4) the cost of treatment. The nature of the solids dissolved in the Madison aquifer water makes it unsuitable for use in coal conversion facilities. However, with treatment, the water would be considered a high-quality water supply probably exceeding the quality of most NGP surface water supplies.

Recent studies indicate that within the Montana and Wyoming portions of the study area where the ground water may be available, it would cost on the average of $39 per acre-foot to bring it to the surface. In comparing the cost of ground water to the cost of surface water in Montana and Wyoming, only those plants within 30 to 40 miles of the point of diversion could obtain surface water at less cost than deep ground water.

A comparison of surface water costs to ground-water costs are shown in table 4-21 for three selected powerplant sites. Similar relative costs would be found throughout the Powder River Basin.

Table 4-21.—*Comparison of water costs* CDP II*

Identification number	Surface† water source	Surface‡ water amount	Surface** water unit cost	Surface water annual cost $	Ground§ water annual cost $
1	Moorhead Reservoir	12,000	89	1,070,000	759,000
2	Bighorn River	12,000	144	1,730,000	794,000
2	Yellowstone River	12,000	162	1,940,000	812,000

*Assumes 1,000 MW powerplant—77 percent capacity factor.
†From Water Work Group draft report.
‡Assumes 12,000 acre-feet per year for 1,000 MW plant when surface water is used, ground-water plant treating water will use somewhat less—9,000 to 10,000 acre-feet per year.
**From Water Work Group draft report—lowest price of choices offered.
§Assumes treatment of lime softening, polymer, and acid addition water cost of $50 per acre-foot. Based on total dissolved solid content of water tested in existing wells. No. 1 is 18 miles north of Gillette, No. 2 is 25 miles east of Hardin, Montana, and No. 3 is 8 miles northwest of Moorhead, Montana.

(c) *Effect of Water Cost on Development.*—It is possible that the projected cost of water will be high enough to affect the extent of coal development. To evaluate that issue, a calculation of

the percentage of water costs to total value of gas produced was made. For the most intensive water user—30,000 acre-feet per year at $350 per acre-foot—the annual water costs were 12.5 percent of the gross revenues (assuming gas sold for $1 per thousand standard cubic feet. If it is a high proportion, there are other available methods—ground water, dry cooling, etc.—which may lower total water costs. Thus, water costs will certainly affect the level of water use and probably plant location as well.

4-10. *Issues Which may Influence Water Cost, Availability, or Use.*—(a) *Agricultural and Industrial Competition for Water.*—Energy companies have purchased partial water rights, options on water rights, and sometimes the entire ranch or farm, in an effort to obtain access to water. When energy companies purchase water rights which have previously been exercised for irrigation, they are in direct competition with agricultural and industrial uses of water. This competition occurs today because of the limitations of the existing supply systems. However, as previously discussed (sec. 4-7), there may be enough total water flowing through the region to satisfy the coal development hypothesized for any of the profiles and to supply an undetermined amount of agricultural depletions by year 2000. The principal condition to this statement is that in the Yellowstone Basin new storage supplies and possible aqueduct systems will have to be constructed.

Even though sufficient water may be available to meet both future agricultural and industrial demands, the price of water will affect its uses. Existing sources, such as converting irrigation water to industrial use can supply water at costs much less than the expected costs from new supply systems. There is an incentive for industry to buy the less expensive water, which may reduce some agricultural activity. This would induce the states, who control the water, to make a choice pertaining to the best use of water.

(b) *Indian Water Rights.*—The resolution of Indian water rights may have significant impact upon NGP water availability. It is difficult at this time to predict the effect and outcome of this issue. First, the priority of Indian water right is contested by the states and some non-Indian water users. Interpretation of priority ranges from the time the Indians settled the land to the date the reservation was established. In addition, the quantity of water reserved is contested. Most Indians claim it is all water flowing on, by, or through the reservation. A thorough discussion of this problem is contained in the separate report entitled "Declaration of Indian Rights to the Natural Resources in the Northern Great Plains."

(c) *Article X of the Yellowstone River Compact.*—According to Article X of the Yellowstone Compact, the transbasin diversion of water from the Yellowstone Drainage Basin can occur only with the concurrence of the signatory states—Wyoming, Montana, and North Dakota. This provision was not completely adhered to in the profile analysis since two plants (in CDP III) supplied with Yellowstone Basin water were sited outside basin boundaries—both south of Gillette, Wyoming.

However, if coal development occurs south of Gillette and if the Article X provision is to be observed, water will have to be provided from some source other than that proposed in the profile analyses.

The two principal alternative sources for surface water are either Oahe Reservoir or the Green River. Water from Oahe will be more expensive than water from within the basin (table 4-22), but it does not violate the Compact. Diversion of water from the Green River, a tributary of the Colorado River, to the Yellowstone Basin will aggravate the salinity and related problems of the Lower Colorado River Basin.

Another alternative water source is ground water. If a sufficient quantity is available in the Gillette area, its cost is much less than any surface water diversion.

Table 4-22.—*Cost of providing water to selected plant sites by alternative conveyance systems*

Conveyance route	Average cost per acre-foot, dollars
(In-Basin)	
Miles City to south of Gillette	232
Bighorn Lake to south of Gillette	286
(Out of basin)	
Green River to south of Gillette*	233
Oahe to south of Gillette	294
Ground water	55

*Analysis done by private consultant. If done with same assumptions as Bureau of Reclamation used for other alternatives, costs would be substantially higher.

4-11. *Impacts of Water Development.*—(a) *Water Quality.*—

(1) *Present conditions.*—The headwaters of most streams in the study area, particularly those originating from snowmelt in the mountains of Wyoming and Montana, have excellent water quality. The available data indicate degradation of the chemical and physical quality as streams progress downward, resulting from natural hydrogeologic conditions and mans' uses.

Except in a few localized areas, the water quality remains satisfactory for irrigation, livestock watering, recreation, fish and wildlife, municipal, and industrial purposes. The few severe local problem areas are usually associated with high levels of activity; municipal or agricultural activity, located on depleted or low-flowing streams, and occur on a seasonal rather than year-round basis.

Natural degradation in stream quality can most easily be described by changes in such physical and chemical parameters as temperature, sediment, and dissolved solids. Temperatures increase as a stream proceeds downstream and the water receives increased exposure to solar radiation and absorbs heat. Likewise, sediment and dissolved solids generally increase as streams proceed toward their mouth. Erosion and subsequent siltation are significant natural problems in the Northern Great Plains area.

These natural changes are also reflected in the biological activity of the aquatic ecosystem. A cold water ecosystem, commonly referred to as a trout stream, exists in the upper reaches of most Northern Great Plains streams. The lower reaches, because of higher temperatures, more sediment, and elevated levels of dissolved materials, generally have a warmer water ecosystem, and in some cases are characterized by more pollution-tolerant species, such as catfish and goldeye fish. However, this warm water ecosystem is often more complex and varied than is the colder water ecosystem.

Agricultural and municipal activities also affect water quality in the Northern Great Plains. Agricultural influences on water quality consist primarily of depletion of streamflows, return flows of irrigation water, crop and pasture land erosion, and feedlot wastes. Sediment, nutrients, and dissolved solids in irrigation return flows to streams have various concentrations depending on farm and water management practices. Average TDS (total dissolved solids) concentrations ranging between 1,000 and 2,500 milligrams per liter have been measured in the Powder, Heart, Knife, Cannonball, Belle Fourche, and Cheyenne Rivers. Concentrations within this range can be detrimental to crops, aquatic life, public use, and industrial use in cooling, boiler water, and food processing.

Suspended sediment concentrations and loads at a given site vary widely throughout the year. The sediment load is normally light in the upper reaches of the major streams, but increases in the middle and lower reaches. While erosion is a significant natural pollution problem, disruption of the land surface due to tilling the soil, grazing, construction activities, and surface-mining activities can and do significantly increase erosion rates.

Washout of feedlot wastes contributes bacteria and organic nutrients to the stream which results in depletion of dissolved oxygen and increased bacteria concentrations. These pollutants can cause changes in the types of aquatic organisms found in the stream and later its recreational and esthetic value.

Wastes generated from municipalities generally contain organics discharged from sewage treatment facilities, and solids washed by runoff from streets and construction sites. These sources contribute suspended and dissolved solids and a variety of nutrients, such as nitrates and phosphates, to the receiving stream.

The average dissolved oxygen level for all stream locations sampled in the Northern Great Plains area ranges from 8.5 to 12 milligrams per liter. However, a marked reduction in oxygen levels has been found during the summer months below some municipal waste water outfalls and in some reaches with low flows resulting from diversions and natural conditions. A zero dissolved oxygen concentration has been recorded for the Heart River near Dickinson and for the Missouri River at Bismarck.

Water temperatures naturally vary significantly from the high mountain streams to the lower streams and reservoirs of the plains. Significant water depletions contribute to the increased temperatures because the lower volume is heated more quickly by solar radiation. The effect of diversions and return flows on stream temperatures is more noticeable in summer months when solar radiation and water demands for domestic uses, irrigation, and industry are high.

Data on existing concentrations of trace elements in the Northern Great Plains are very limited. Trace elements such as mercury, lead, flourine, boron, and so forth, are of importance because of their harmful effects on crops, livestock, aquatic life, and humans. All activities which cause the concentration of dissolved solids to increase can potentially increase the concentration of trace elements. The limited available data indicate that harmful concentrations of trace elements are not present in Northern Great Plains streams.

Table 4-23 presents a water quality summary for major streams in the Northern Great Plains. A more extensive summary and discussion on the existing water quality of the region is available in the NGPRP Water Quality Subgroup Report.

The present emphasis of the Federal and state pollution control programs is to clean up effluent discharges generally referred to as point sources. Regulation of discharges of municipal, industrial, and feedlot wastes has resulted in an overall improvement in water quality and will continue to be effective in controlling water pollution. The pollution problems caused by such activities as land surface disruption, stream dewatering, and ground-water contamination are not easily abated by conventional water treatment devices and will require an extended effort to control their potential pollution effects.

(2) *Potential changes in water quality.*—Changes in water quality are quite likely should development occur at levels described by CDP's II and III. The extent of this change will depend on the type of environmental regulation and planning instituted prior to development. Analysis to date shows very minor or no changes in water quality resulting from development at the CDP I level. The analytical tools used for analysis lack sensitivity to accurately predict the changes in water quality from a single mine or industrial plant. Therefore, the local impacts which may result from low-level coal development are not predicted by these tools.

Surface Mining Impacts.—The surface mining of coal is one of the major activities which can cause changes in water quality. Removal of water which infiltrates active mines may cause pollution if adequate treatment is not practiced. Runoff from disturbed areas, inadequately treated, will contain sediment, dissolved solids, trace elements, and possibly nutrients. Strip mining, which breaks up and exposes large amounts of earth material, increases the concentration of dissolved salts, nutrients, and trace elements in ground water, which then may flow into a nearby stream.

Recent sampling of shallow ground water at mines near Colstrip and Decker, Montana, have indicated the pollution potential. Data from the Colstrip area show relatively high concentrations of calcium, magnesium, sulfate, and total dissolved solids in waters which drain from spoil banks. In the same area, concentrations of two trace elements in spoil bank waters (manganese and lead) were found to exceed the U.S. Public Health Service drinking water standards. The drainage from strip mining activity in the vicinity of Colstrip appears to contribute to significant increases in total dissolved solids in surface water (a rise from

Table 4-23.–*Water quality summary*

Storage location	Temp C	DO mg/l	BOD mg/l	pH units	Flow cfs	TDS mg/l	SS mg/l	T-NO_3 as N mg/l	NH_3 mg/l	T-PO_4 as P mg/l	Trace elements Pb ug/l	Cu ug/l	Hg ug/l	F ug/l	Se ug/l	Al ug/l	8 ug/l	Zn ug/l	Total hardness mg/l
8ighorn River at Bighorn, Mont.																			
Maximum value	27.2	–	–	8.5	23,000	836	21,100	0.50	–	–	–	–	–	700	–	–	270.0	–	643
Minimum value	0.0	–	–	7.0	612	471	42	0.01	–	–	–	–	–	200	–	–	30.0	–	169
Average value	12.8	–	–	7.7	4,249	608	4,088	0.18	–	–	–	–	–	400	–	–	133.5	–	338
Tongue River at Miles City, Mont.																			
Maximum value	29.4	–	–	8.8	4,139	816	–	0.10	–	–	–	–	–	800	–	–	1,250.0	–	568
Minimum value	0.0	–	–	6.9	16	262	–	0.01	–	–	–	–	–	200	–	–	10.0	–	104
Average value	10.5	–	–	7.9	594	570	–	0.04	–	–	–	–	–	361	–	–	137.3	–	324
Powder River at Moorhead, Mont.																			
Maximum value	28.5	12.4	10.0	8.5	4,600	4,080	–	–	0.61	3.20	5.0	30.0	0.9	2,200	11.0	–	448.0	32.0	1,220
Minimum value	0.0	5.2	0.6	7.4	8	676	–	–	0.00	0.0	0.0	0.0	0.0	0	0.0	–	241.0	0.0	0
Average value	10.5	9.0	3.0	8.0	642	1,552	–	–	0.09	0.54	1.0	10.4	0.2	500	3.7	–	274.8	16.0	615
Yellowstone River near Sidney, Mont.																			
Maximum value	24.4	12.6	3.3	8.9	65,240	655	15,500	0.69	0.26	2.70	0.0	10.0	–	800	–	200.0	260.0	0.0	403
Minimum value	0.0	7.4	0.9	6.9	1,149	230	167	0.00	0.00	0.01	0.0	0.0	–	100	–	100.0	20.0	0.0	90
Average value	11.3	9.8	1.8	7.8	14,527	460	2,308	0.20	0.06	0.32	0.0	2.5	–	449	–	150.0	146.4	0.0	245
Knife River at Hazen, N. Dak.																			
Maximum value	24.0	–	–	8.3	5,930	1,510	–	2.40	–	–	–	–	–	900	–	–	1,300.0	–	530
Minimum value	0.0	–	–	7.0	13	204	–	0.00	–	–	–	–	–	0	–	–	0.0	–	81
Average value	9.1	–	–	7.9	392	1,004	–	1.15	–	–	–	–	–	400	–	–	263.2	–	320
Heart River at Mandan, N. Dak.																			
Maximum value	25.0	16.2	8.9	9.0	–	2,280	–	–	–	0.76	–	–	–	–	–	–	–	–	515
Minimum value	0.0	3.7	0.8	7.0	–	175	–	–	–	0.01	–	–	–	–	–	–	–	–	110
Average value	10.3	9.6	2.9	8.0	–	844	–	–	–	0.11	–	–	–	–	–	–	–	–	290
Cannonball River at Breien, N. Dak.																			
Maximum value	24.0	–	–	8.3	2,770	1,960	–	4.80	–	0.21	–	–	–	1,400	–	–	860.0	–	720
Minimum value	0.0	–	–	7.2	15	285	–	1.00	–	0.0	–	–	–	100	–	–	0.0	–	140
Average value	10.2	–	–	7.8	414	1,139	–	2.68	–	0.02	–	–	–	546	–	–	346.0	–	429
Missouri River at 8ismarck, N. Dak.																			
Maximum value	22.0	14.3	6.0	8.6	36,400	653	–	–	0.90	0.07	60.0	50.0	–	700	0.1	59.0	360.0	42.0	706
Minimum value	0.0	6.1	0.0	7.7	1,040	268	–	–	0.00	0.01	4.0	10.0	–	450	0.01	9.0	91.0	2.0	4
Average value	8.3	10.6	1.1	8.3	18,239	425	–	–	0.24	0.04	33.6	22.0	–	519	0.2	37.3	217.0	20.4	212
Belle Fourche River near Elm Springs, S. Dak.																			
Maximum value	29.0	12.9	16.0	9.0	8,560	4,820	13,600	8.40	0.72	0.3	11.0	80.0	0.3	2,700	–	179.0	710.0	40.0	2,440
Minimum value	0.0	4.8	0.2	6.5	2.8	512	7	0.11	0.01	0.0	0.0	5.0	0.0	300	–	0.0	80.0	0.0	300
Average value	9.7	9.2	3.3	7.7	361	2,071	1,537	3.25	0.24	0.53	0.9	34.2	0.1	608	–	114.5	342.2	18.9	1,110
Cheyenne River at Edgemont, S. Dak.																			
Maximum value	25.0	11.8	9.4	8.4	609	7,100	–	2.00	2.40	5.80	10.0	75.0	0.3	1,100	20.0	100.0	770.0	490.0	3,100
Minimum value	0.0	0.2	0.5	4.2	0.3	695	–	0.00	0.00	0.00	0.0	3.0	0.1	200	0.0	0.0	10.0	20.0	260
Average value	10.4	8.6	2.9	7.7	61	3,551	–	0.44	0.35	0.49	2.1	25.5	0.2	600	5.1	50.0	346.9	132.1	1,476

Legend:
DO–Dissolved Oxygen
BOD–Biochemical Oxygen Demand
pH–Ionic 8alance, 1-7 acid, 8-14 basic
Flow/cfs–Flow, cubic feet per second (ft^3/s)
TDS–Total Dissolved Solids
SS–Suspended Solids
T-NO_3 as N–Total Nitrate as Nitrogen
NH_3–Ammonia
T-PO_4 as P–Total Phosphate as Phosphorus
Pb–Lead
Cu–Copper
Hg–Mercury
F–Fluorine
Se–Selenium
Al–Aluminum
B–Boron
Zn–Zinc
mg/l–Milligrams per liter
ug/l–Micrograms per liter
– No Data Available

about 2,200 to 3,500 milligrams per liter). In the Decker area, the major chemical consittuents in water draining into the mine are sodium, bicarbonate, and sulfate. Since the ground water in the area contains little, if any, sulfate, a sizable amount must be leached as a result of the mining operations. The relatively strong mineralization of overburden, demonstrated by the occurrence of saline seeps in the area, is a major if not the primary cause for changes in the area's ground-water quality. Although no conclusive demonstration is available to indicate the direct effect of mining operations on surface water quality, these shallow ground-water studies indicate to some extent the potential for surface water quality degradation.

An increase in the concentration of dissolved solids, including trace elements and nutrients in ground water will, in many cases, be transported to a stream or river by underground flow. Mines located close to streams have the greatest potential for rapid degradation of surface water quality.

The persistent nature of this type of pollution and the difficulity in abating it poses one of the most difficult environmental problems for mining operations. Further data collection and analysis is needed to better understand the potential for water quality problems resulting from mining and to evaluate schemes for minimizing water quality degradation.

Coal Gasification and Powerplant Impacts.—Coal conversion facilities also have the potential to cause water quality changes. These industrial plants will utilize water, consumptively reducing flows and thereby lowering the transport and waste assimilative ability of the river. Effluents containing elevated temperatures, dissolved solids, trace elements, and certain organics from gasification may cause water quality degradation. Industrial plants can be designed to use a minimum amount of water and have very little, or no effluent. Most "no discharge" plants presently utilize large solar evaporation ponds for ultimate waste disposal. The impact of these ponds on ground water, wildlife, and water fowl are very site oriented, but are generally considered preferable to operations that discharge into a nearby stream, provided no substantial seepage occurs.

Water quality changes that have been quantitatively evaluated by the NGPRP to date have assumed that the industrial plants will use larger than necessary amounts of water and will therefore have an effluent. Should smaller quantities of water be used and plants built having no discharges, overall regional water quality changes resulting from coal-energy

conversion plants will probably be less. Of particularr significance is that water supply streams such as the Bighorn will have greater flows as less diversion will be needed, while effluent-receiving streams such as the Tongue and Powder Rivers will have lower flows as they would no longer receive effluents. If nondischarge plants become the rule, nonpoint sources of pollution associated with coal development will become increasingly important, as effluents will diminish.

One water quality parameter, TDS (total dissolved solids), can be sufficiently modeled so that rough estimates of the degree of water quality change can be made. The projections are based entirely on estimates of consumptive use of water by coal-energy conversion plants and do not include TDS increases caused by runoff from disturbed areas, leaching of mine spoils, or any increase in agriculture or other water use. These other sources of TDS are not incorporated into the projections because they could not be quantified; however, they are important to water quality. These projections are based on numerous assumptions and need refinement as more and better data are compiled.

Powerplants of 1,000 MW size are assumed to have an annual discharge of 5,000 acre-feet, thereby concentrating the TDS by a factor[8] of 3.8 times the intake concentration. Gasification plants (250 million cubic feet per day) are assumed to range in discharge from 20,000 to 10,000 acre-feet reflecting a degree of uncertainty about their operation. The concentration factor for gasification plants then has a range of 1.5 to 3.0. These numbers, along with estimates of existing TDS concentrations in rivers of the region, are used to make the TDS projections.

These projections indicate that the average annual concentration of total dissolved solids in the Missouri River at Bismarck, North Dakota, would increase for CDP III from 436 milligrams per liter to between 465 and 500[9] milligrams per liter or approximately 7 to 15 percent. For CDP II level of development, projected increases for the Missouri River at Bismarck are between 445 milligrams per liter, a 2 percent increase and 470 milligrams per liter, an 8 percent increase. The large volume of water which flows in the Missouri River below Garrison Dam—approximately 15 to 16 million acre-feet per year—has a tremendous dilution capability which is the principal reason for the small increases in these TDS projections.

[8] $\frac{\text{Intake volume}}{\text{Effluent volume}}$ = Concentration factor

[9] Includes the effects of a reduction in flow in the Missouri River at Bismarck resulting from development of the Garrison Irrigation Project.

Table 4-24 shows the results of TDS projections for some other potentially impacted rivers of the region. In the case of the Powder and Knife Rivers a decrease in the TDS concentration is indicated as being possible. This finding results from using a water supply source with a relatively low TDS concentration (Bighorn River and Lake Sakakawea) and discharging into water with a relatively high TDS concentration. The low TDS concentrating factor for gasification plants of 1.5 is another major reason for the results which indicate a possible improvement in TDS concentration in the Powder and Knife Rivers.

Table 4-24.–*Projected annual average total dissolved solids concentrations resulting from assumed discharge from coal gasification and power generation plants*

River and location	Historical average concentration (mg/l)*	Range of TDS projections (mg/l)	
		CDP II	CDP III
Tongue River at Miles City, Montana	560	700-790	760-910
Powder River at Moorhead, Montana	1,552	1,410-1,590	1,280-1,770
Yellowstone River near Sidney, Montana	460	480-490	510-530
Knife River at Hazen, North Dakota	1,004	870-1,100	790,1,150
Heart River near Mandan, North Dakota	844	860-870	850-890
Missouri River at Bismarck, North Dakota	436	445-470	465-500

*Milligrams per liter

Note: These projections are based on numerous assumptions and need refinement as more and better data are compiled. Therefore, this table should be used only to make broad inferences about potential TDS concentrations.

The TDS projections indicate that of the rivers analyzed, the Tongue River has the greatest potential for being impacted by discharges from coal conversion facilities. Projected increases in TDS range from 25 to 41 percent for CDP II and 36 to 62 percent for CDP III. This potential TDS increase is due in part to the relative low dilution capacity (flow) in the Tongue River compared with the Yellowstone and Missouri Rivers. Also, the Tongue River historically has low TDS concentrations compared to the other Yellowstone and Missouri

River tributaries analyzed, and therefore discharges with high TDS concentrations will result in a greater change in the Tongue River than in the Powder, Knife, and Heart Rivers.

TDS projections for annual low-flow conditions, show an even greater increase in TDS concentration. For example under CDP III and flow conditions which occurred in 1966, the Tongue River at Miles City is projected to have an annual TDS concentration from 880 to 1,120 milligrams per liter. For CDP II, the projected TDS range is from 800 to 960 milligrams per liter. The average TDS concentration during 1966 was 645 milligrams per liter. For the once-in-10-year low-flow conditions, again 1966, the Yellowstone River at Sidney is projected to have TDS increases from 500 to 510 milligrams per liter for CDP II and from 540 to 570 milligrams per liter for CDP III. The average TDS concentration at Sidney during 1966 was 491 milligrams per liter. For more information on these projections including monthly projections, the reader is referred to the report of the NGPRP Water Quality Subgroup.

The importance to water users of these increases in TDS concentrations is dependent upon many factors which have not been adequately assessed to make any specific conclusions. Generally, TDS concentrations in excess of 1,000 milligrams per liter are considered adverse for irrigation of many crops but actual limits vary considerably, up or down, according to soil composition, drainage, and water management practices. The EPA has proposed a maximum acceptable TDS concentration for livestock drinking water of 3,000 milligrams per liter but higher concentrations are tolerated by livestock in the region. Generally, water is considered good for public drinking supplies if the TDS concentration does not exceed 500 milligrams per liter but many communities in the region utilize water with much higher TDS concentration.

An important consideration in evaluating the effects of higher TDS concentrations is the constituent dissolved solids which comprise the total. Certain constituents such as sodium and boron are harmful to crops, and others such as sulfates and chlorides are undesirable for public water supplies. Many of the trace elements can be toxic to aquatic life, livestock, and humans. The potential for water quality problems from an increase of certain dissolved constituents as a result of coal-energy development is unknown and will require further data collection and study. Initial work concerning the assessment of potential trace element concentration increases in the NGP is being conducted by EPA.

Sewage Treatment Impacts.—An influx of people, necessary to support development, is also a potential source of changes in water quality. Rapidly growing communities traditionally have a problem with inadequate sewage treatment facilities. There is normally a lag between the arrival of large numbers of people and the institutional and financial framework required to build additional treatment facilities. The associated problems of nutrification, dissolved oxygen depletion, and aquatic toxicity resulting from poorly treated sewage can cause serious degradation of water quality. This potential water quality problem will be most serious for rapidly growing towns with moderate to large populations discharging to seasonally low-flowing streams.

Discharges of treated domestic wastes can cause significant depletion of dissolved oxygen when the capacity of the stream to biologically assimilate the wastes is less than that discharged into the stream. Dissolved oxygen analyses were made for Billings and Miles City, Montana, located along the Yellowstone River and for Sheridan, Wyoming, located along Goose Creek, a tributary of the Tongue River. These municipalities were chosen because of the availability of USGS stream data, and because these sites represent a range of flow and population impacts which might result from coal-energy development. At all three locations, secondary treatment was assumed as defined by EPA.[10] Complete mixing of wastes in the stream was also assumed. It was found that during August low-flow conditions, an estimated population for Billings corresponding to CDP III would not cause a violation of the dissolved oxygen standard in the Yellowstone River. Similarly for Miles City no violation of the DO (dissolved oxygen) standard was calculated using the August instream flow requirement (suggested minimum flows used elsewhere in this report) as the low flow for that location. Sheridan, Wyoming, located along a low-flowing steam, was shown to have a high potential for violating the dissolved oxygen standard depending upon the estimated influx of people into that city. A population in Sheridan of between 14 and 23 thousand with secondary waste treatment is estimated to result in violation of the dissolved oxygen standard. For a complete explanation of this analysis, see the NGPRP report of the Water Quality Subgroup.

In general these dissolved oxygen analyses imply that with secondary waste treatment, the Yellowstone and Missouri River main stems will not be significantly impacted with respect to dissolved oxygen as a result of current population influx estimates and the

[10] Federal Register, August 17, 1973, vol 38, No. 159, part II.

aqueduct diversions discussed earlier. Conversely, cities and towns discharging into creeks and low-flowing streams of the region can expect to go beyond secondary treatment of domestic wastes, or limit the discharge rate, if significant population growth is experienced in the area. These areas include such municipalities as Sheridan, Buffalo, Gillette, Dickinson, and potentially many others.

In this analysis of DO impacts, an important assumption has been made which should be emphasized again, which is that secondary treatment as defined by EPA is assumed for all municipal waste discharges. Since the secondary treatment standard is required for all municipalities by July of 1977, this assumption is reasonable. But the realities of financing the upgrading of existing treatment facilities may cause a lag in implementation of this standard. This situation is especially true for small, rapidly growing communities which require substantial revenue to provide secondary treatment for future populations but lack the economic base upon which to generate the required dollars. The existence of such communities will most likely be fostered by rapid coal-energy development. If so, State and Federal Governments must recognize this problem at an early stage and formulate plans to deal with the local needs. Otherwise, the pollution of streams and rivers will be more drastic than revealed by this report.

(b) *Shallow Ground-water Impacts.*—Coal development in the Northern Great Plains will impact shallow ground water in both a physical and a chemical manner. Water levels in wells close to mine operations will be lowered as long as mining continues, and even after mining, flows into some wells may remain low. Pollution of ground water from leaching of spoils may occur, but would probably have only local effects. Wells drilled in mine spoils will produce less water of lower quality than before mining. The means and costs of avoiding these impacts are largely unknown. The complexity of the shallow aquifer system makes it difficult, however, to accurately predict the quantitative impacts of the exploration, extraction, and use phases of coal development without first having an accurate geohydrologic description of each site. As a result, the discussion presents only ranges in or types of impacts as they have been measured at a few sites or as may be possible under theoretical conditions.

The most significant impacts on the shallow ground-water system may come from mining. Exploration, primarily through drilling, will encounter situations where unplugged wells will flow and where uncased holes will serve as interconnections between aquifers containing water of

varying quality. Mining, and particular surface mining, will serve both to lower the local water table and to alter the chemical quality of the water passing through the disturbed overburden or spoils. The coals form all or a significant part of the shallow aquifers in the region. Removal of the coal thus removes part of the water-carrying strata. The resultant open trench in the active coal mine will thus serve as a point of discharge for the shallow aquifers interrupted by the trench. The water seeping into the trench may amount to a few hundred thousand gallons per day which can be pumped out to facilitate mining. The trench acts as a large well causing a lowering of the water table, usually to a distance of from 1 to 6 or so miles from the mine, depending upon the geologic structure of the area. The vertical extent of water-table drawdown will not be greater than the depth of the trench (currently up to about 200 feet) and this amount will normally be found only adjacent to and on the downstream side of the trench. The drawdown could reduce the amount of water available to wells completed in the coals and could at least require relocation of pumps and deepening of wells.

As spoils material are returned to the trench, the water table will begin to rise. After mining is completed, the depth to water will be about equal to that encountered prior to mining, as long as the final elevation of the rehabilitated terrain remains about the same as existed prior to mining and the areal extent of the mining is relatively small. If the final surface elevations of the terrain are significantly below the original elevations, internal drainage could occur and salt accumulation caused by evaporation could be a problem. If extensive mining is practiced over the region, areas of recharge may be disturbed and regional water tables may be changed over a large area. There is no experience to date with large-scale mining over an entire coal basin and accurate predictions of the impact of mining on the shallow ground-water system require extensive site-specific investigations that are not yet available.

The total effect of surface mining on the physical water system will be related to the depth of the operation and the total horizontal extent of the operation. For example, at Decker, Montana, a new mine has been initiated with an open cut about 12,000 feet long and 200 feet deep. It is estimated that the current operations intercept, through the coal and associated aquifers, from 200,000 to 400,000 gallons of water per day. Water-level declines radiate between 3/4 and 1-1/2 miles from the mine after about 15 years of mining. The impact situation at Decker may be limited by faulting (vertical displacement) of the coal aquifer.

When the spoils material or overburden is replaced in the mine, it assumes a porosity and permeability dissimilar to that possessed by the undisturbed material. Generally, the spoil material has a higher porosity and lower horizontal permeability than the overburden had prior to mining. This indicates that there is more void space and generally greater downward dispersion of water entering the material. Because there is likely to be less concentration of water in horizontal aquifers within the replaced overburden, wells drilled into it may not have the ability to produce water at as high a rate as that prior to mining.

The spoils materials provide a source of dissolved solids for the percolating ground waters that apparently exceeds the sources available to waters in undisturbed overburden and coal. Increases in dissolved solids contents of water percolating through spoils have been shown in laboratory experiments and in the field.

Major leachable ions include sodium, calcium, sulphate, and carbonate. In the case of limited sampling at Colstrip, most ions measured in water collected from spoils showed an increase attributable to seepage through the spoils.

The concentrations were generally below recommended limits for beneficial uses with the exception of arsenic, lead, manganese, and sulphate, which appeared to consistently exceed the Public Health Service Drinking Water Standards. It should be noted that conclusive data are limited and that this comparison was made only for drinking water standards.

Under certain circumstances, water carried in the coal is similar to water passing through charcoal filters–it is relatively clean and can in fact be somewhat filtered. When that water can no longer flow through the coals because of removal of those coals, but instead passes through broken sand, shale, and clayey spoils materials, it can be reasoned that the water will pick up minerals. It might also be reasoned that the rate of pickup will decrease with time. However, water from old spoils placed some 45 to 50 years ago at Colstrip, Montana, have suggested that the poor quality of these older waters is equivalent to those waters collected from much younger spoils at the same site. A decrease in the amount of leaching of ions with time has not yet been noted.

In the cases of mining and use, the probability of chemical deterioration of ground water is high. However, the lateral and vertical extent of such deterioration remains unknown. Unfortunately, no measurements were made in the past. Similarly, the length of time that increased leaching will take place is not known. Therefore, it is difficult to predict what, if any,

long-term or areally ranging chemical problems coal development may cause users of these shallow ground waters. Intuitively, it appears that the small yields produced by these aquifers indicate that travel velocities of the waters are or will be moderately slow and that contaminants may not range great distances. However, with slow velocities, recovery rates of the water table would likewise be slow and the physical impact of mining on ground water may outweigh, in the short term, the chemical impacts.

The cost of avoiding these impacts include the costs of tests and measurement of spoil properties and aquifer hydrology, special handling of spoils for purposes such as: (1) maintaining aquifer flow in the same strata, (2) insuring sufficient permeability (transmitivity) to insure continued flows, (3) placement of less saline spoils at aquifer layers, (4) treatment of surface configuration, and (5) insuring control of leaching or preserve recharge, revegation, and other surface treatment to insure desirable runoff or recharge rates. Adequate information for preplanning of mining is at present largely nonexistent, and the costs of any of the above-mentioned measures is unknown.

(c) *Impact of Water Development on Land Resources.*—The suggested streamflow establishes a criteria for estimating the impact of flow depletions on the aquatic ecosystem. All specific CDP water supply alternatives examined in this report met the instream flow requirements except the Hardin aqueduct diversion for CDP III development. Although meeting the NGPRP instream flow requirement is not certain to maintain the existing aquatic life, the result of not meeting them indicates a tremendous potential for inducing stress and therefore altering the type of aquatic exosystem.

There are other basic environmental considerations that must be made in evaluating impact of water supply alternatives particularly those utilizing aqueducts and reservoirs.

Most of the land disturbed during the construction of a buried pipeline aqueduct may be restored within a few years, although its value as wildlife habitat may be different than it originally was. A longer term loss of grazing and wildlife uses from aqueducts would result from placement of a roadway along the aqueduct route to facilitate maintenance of facilities. Crossing through streams would result in temporary degradation of downstream water quality and loss of habitat for some aquatic organisms.

With reservoir construction, there is a direct irreplaceable loss of land due to permanent flooding. As an example, 556,000 acres of Missouri River bottomlands and adjacent uplands were

lost when Lake Sakakawea was formed. Seasonal flooding of downstream riparian habitat, flushing of stream channels, water quality characteristics, and other parameters are modified downstream subsequent to impoundment. Some of these changes may be beneficial while others are generally detrimental to existing fish and wildlife resources.

Generally, aqueducts diverting water from an existing storage facility exert less severe impacts on terrestrial wildlife than do new impoundments. Impacts on aquatic resources are often dependent on the quantity of water left in the stream to meet instream flow requirements and maintain riparian habitat and water quality.

4-12. *Ambient Air Quality.*–The Northern Great Plains is relatively free of large-scale air pollution problems. Extremely clean air is a trademark with visibilities of 50 miles, or more, commonplace. The "big sky" phenomenon is treasured by people who live in the region and by those who visit it. A discussion of the area plus an assessment of the coal development impacts upon it follows.

The frequency and intensity of air movement in the study area (fig. 4-7) should result in good dispersion conditions. Average annual wind speeds range from 8 to 14 miles per hour, with Casper, Wyoming, being the highest (fig. 4-8). Winter chinook winds occurring near the eastern side of the Rocky Mountains may last for several days and reach 25 to 50 miles per hours.

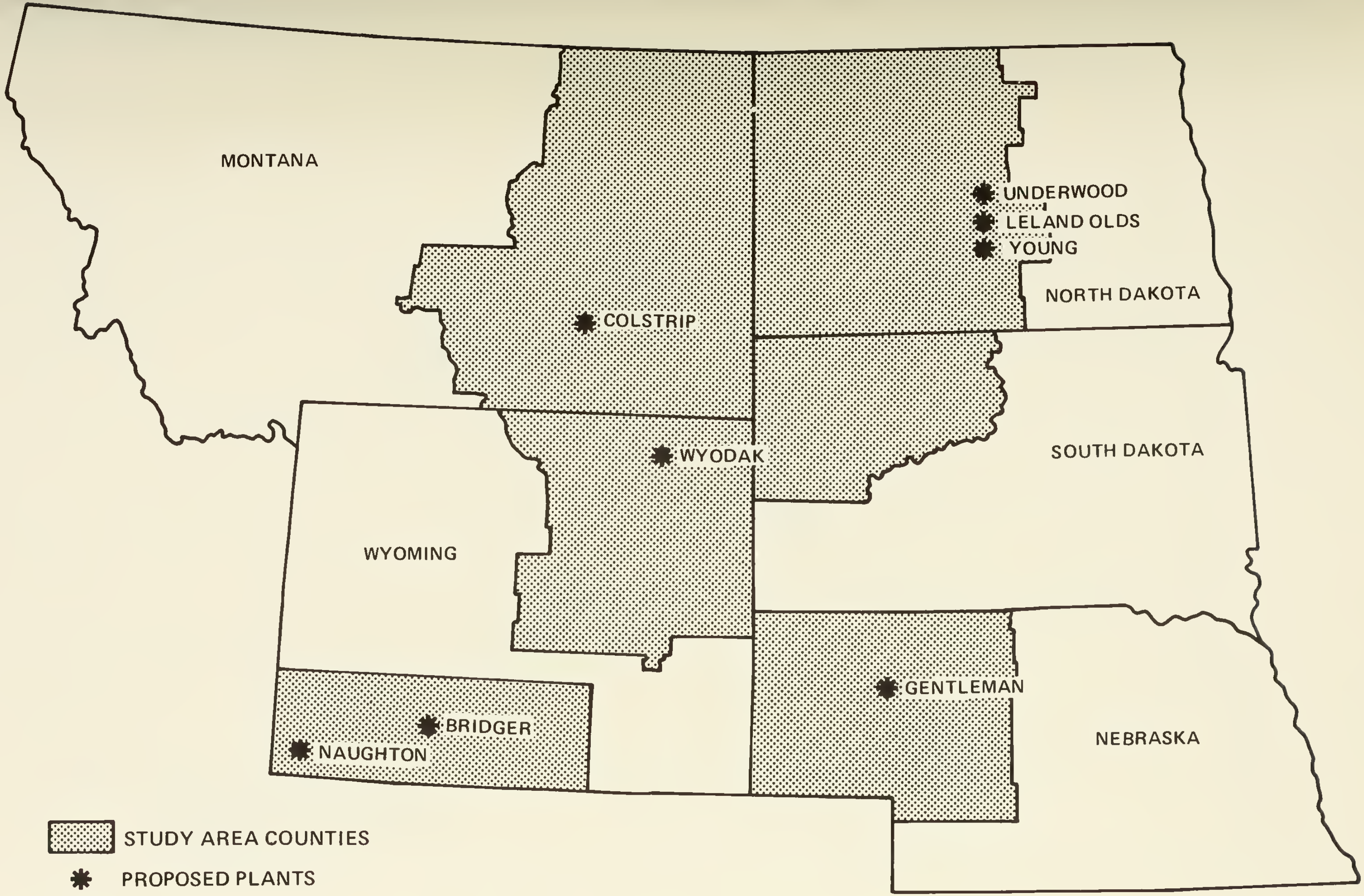
The dispersive characteristics of a plume are also dependent upon the mixing layer height, which is that layer of air next to the earth's surface where vertical mixing occurs. Shallower layers imply a greater potential for high air pollution concentrations. A summary of mixing heights encountered in the study area is presented in table 4-25.

Table 4-25.–*Northern Great Plains mean mixing heights (meters)**

	Annual	Winter	Spring	Summer	Autumn
Morning	300-400	300-400	400-500	300	300
Afternoon	1,400-1,600 (N. Dak., S. Dak., and Nebr.) 1,000-2,400 (Wyo. and Mont.)	600-1,000 (N. Dak., S. Dak., Mont.) 1,000-1,200 (Wyo.)	2,000-2,400 2,800 (S. Dak. and Wyo.)	2,000-3,000	1,400-2,000

*To convert meters to feet multiply by 3.28.

In general, the worst dispersive conditions occur in the morning and during the winter afternoons. Little data is available on the frequency and extent of temperature inversions that cause localized stagnant airmasses and concentrate air pollutants. Data to define this phenomena for five locations in the NGP are being collected and will be available in 1976.



NOTE:
Southwestern Wyoming was included in the assessment of coal development impacts upon air quality because of the presence of two major developments of strippable coal deposits in the area.

Figure 4-7. Atmospheric aspects study area.

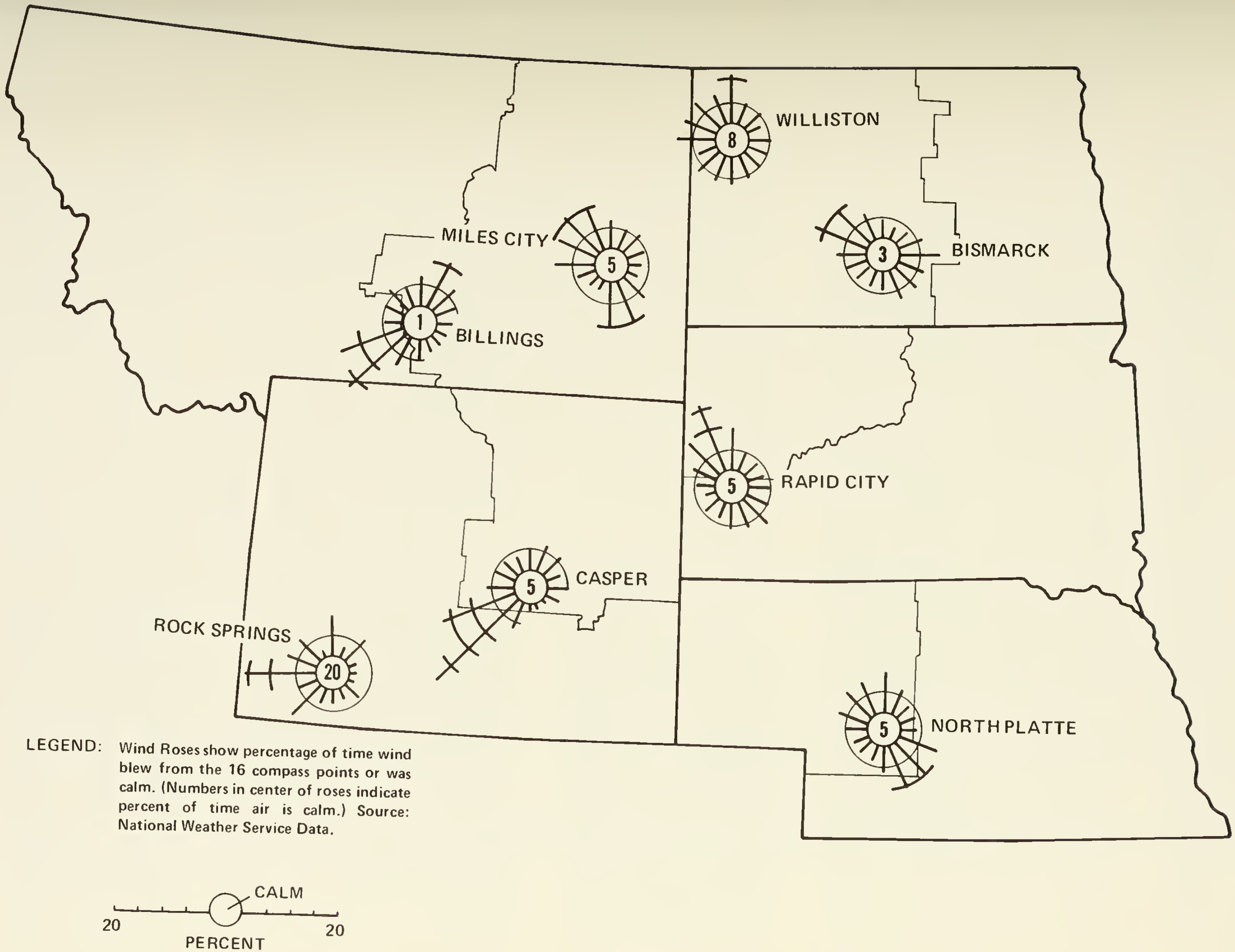


Figure 4-8. Surface wind roses annual.

The annual mean relative humidity for the study area is 60 percent. The study area receives between 60 and 70 percent of total possible sunshine. These are important factors because the conversion of SO_2 to sulfate is believed to be a function of relative humidity and the converstion of hydrocarbons and nitrogen oxides to photochemical oxidants occurs in the presence of sunlight.

Presently the major manmade sources of air plllution in the NGP are farming, grain processing, power generating, oil refining, and production of lumber. The total emissions are small when compared to emissions in the Los Angeles Basin, the industrial areas of Ohio or Pennsylvania, or even the metropolitan Denver area. An estimate of the amount of five common air pollutants emitted in 1972 is shown in table 4-26. A comprehensive description of air quality in the NGP is not possible because at present there are only 30 air quality monitoring stations in the NGP. This system has been augmented with nonurban monitoring stations, and the additional data will be available in 1975.

Figures 4-9 through 4-13 show pollutant concentrations from selected sites throughout the NGP. Also shown on these figures are the primary and secondary NAAQS (National Ambient Air Quality Standards) and state air quality standards. Primary standards have been established for those pollutants that are harmful to human health. The effects of these levels of pollutants occur primarily in the respiratory, pulmonary, and circulatory systems. Secondary standards have been established to protect plant and animal life, and materials.

4-13. *Impact of Coal Conversion on Air Quality*.—(a) *Primary Impacts*.—Federal and State air pollution control laws require attainment and maintenance of air quality at a level that will not adversely impact human health and welfare, animal or plant life, or materials. Therefore, it must be assumed that the emissions from coal conversion facilities or pollutants from other sources will be controlled so as not to violate these laws. For this reason, the possibility of adverse environmental effects from air pollutants is not predicted unless future research indicates that the present standards are not adequate, or that compounds that are harmful are not covered by a standard.

The conversion of coal to produce electricity or synthetic natural gas will result in the production of many kinds of air pollutants, including particulates, sulfur oxides, nitrogen oxides, hydrocarbons, and carbon monoxide. Major pollutants emitted from a powerplant will be particulates, sulfur oxides, and nitrogen oxides. Major emissions from gasification plants appear

Table 4-26.—*Estimated emissions—1972 data in tons per year*

	Montana	Nebraska	North Dakota	South Dakota	Wyoming	Los Angeles	Cleveland	Denver
Particulate	256,000	768,000	116,000	59,000	154,000	86,000	271,000	12,000
Sulfur oxides	413,000	82,000	88,000	14,000	73,000	115,000	738,000	27,000
Nitrogen oxides	110,000	87,000	144,000	78,000	106,000	573,000	367,000	139,000
Hydrocarbon	179,000	151,000	113,000	110,000	102,000	1,167,000	2,278,000	174,000
Carbon monoxide	1,287,000	733,000	567,000	568,000	470,000	4,128,000	3,372,000	873,000

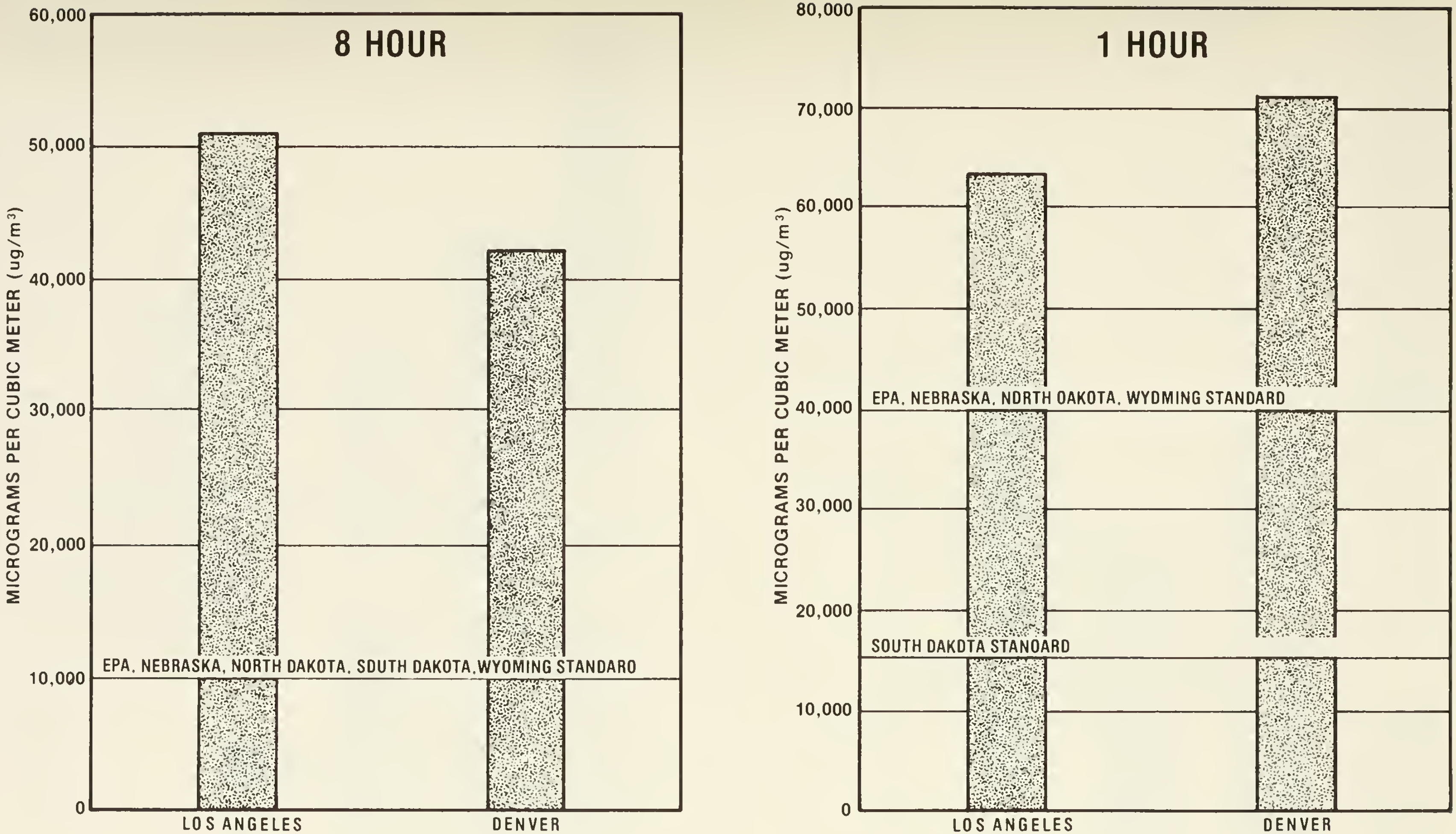


Figure 4-9. Carbon monoxide–ambient air quality data and standards.

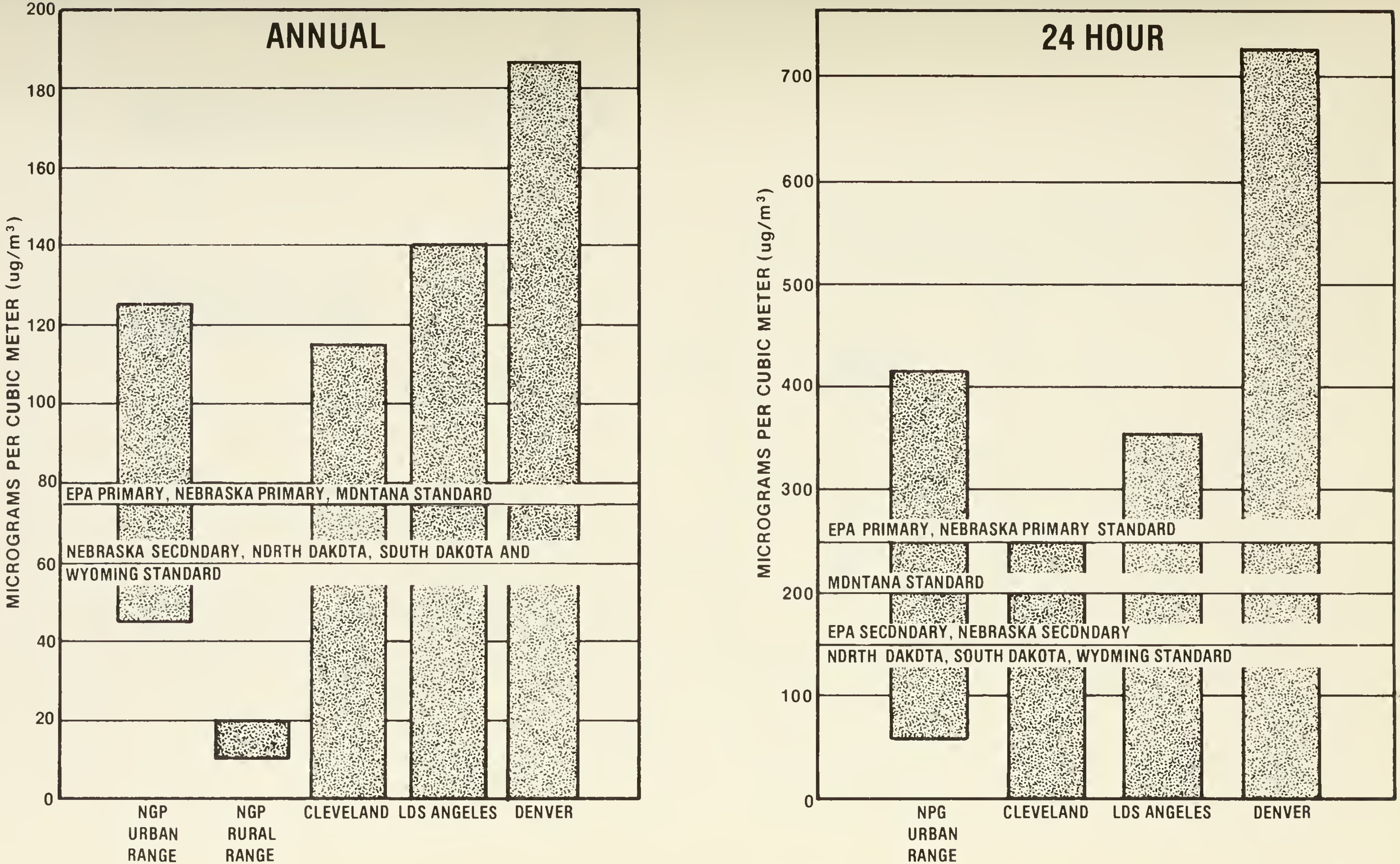


Figure 4-10. Particulate matter–ambient air quality data and standards.

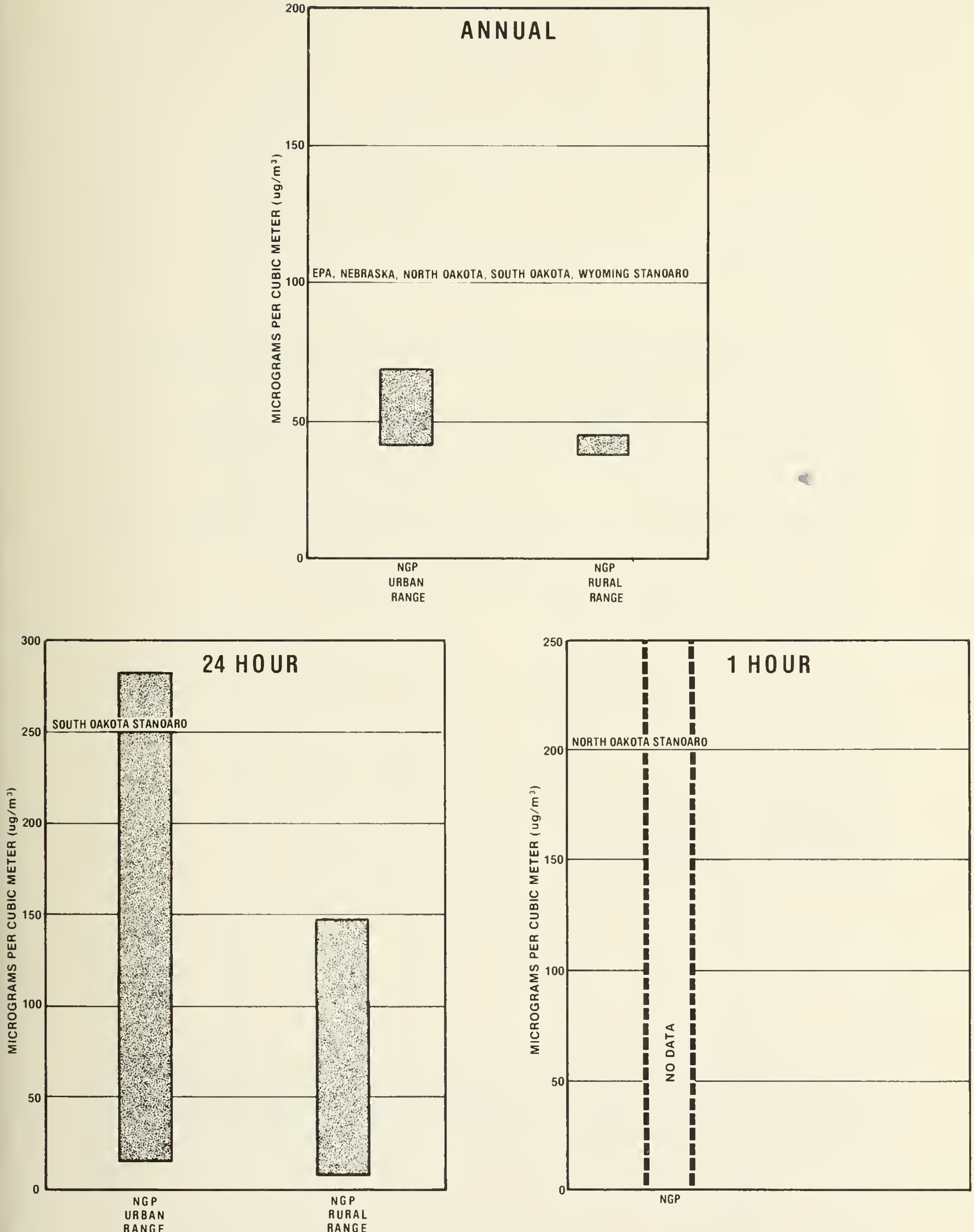
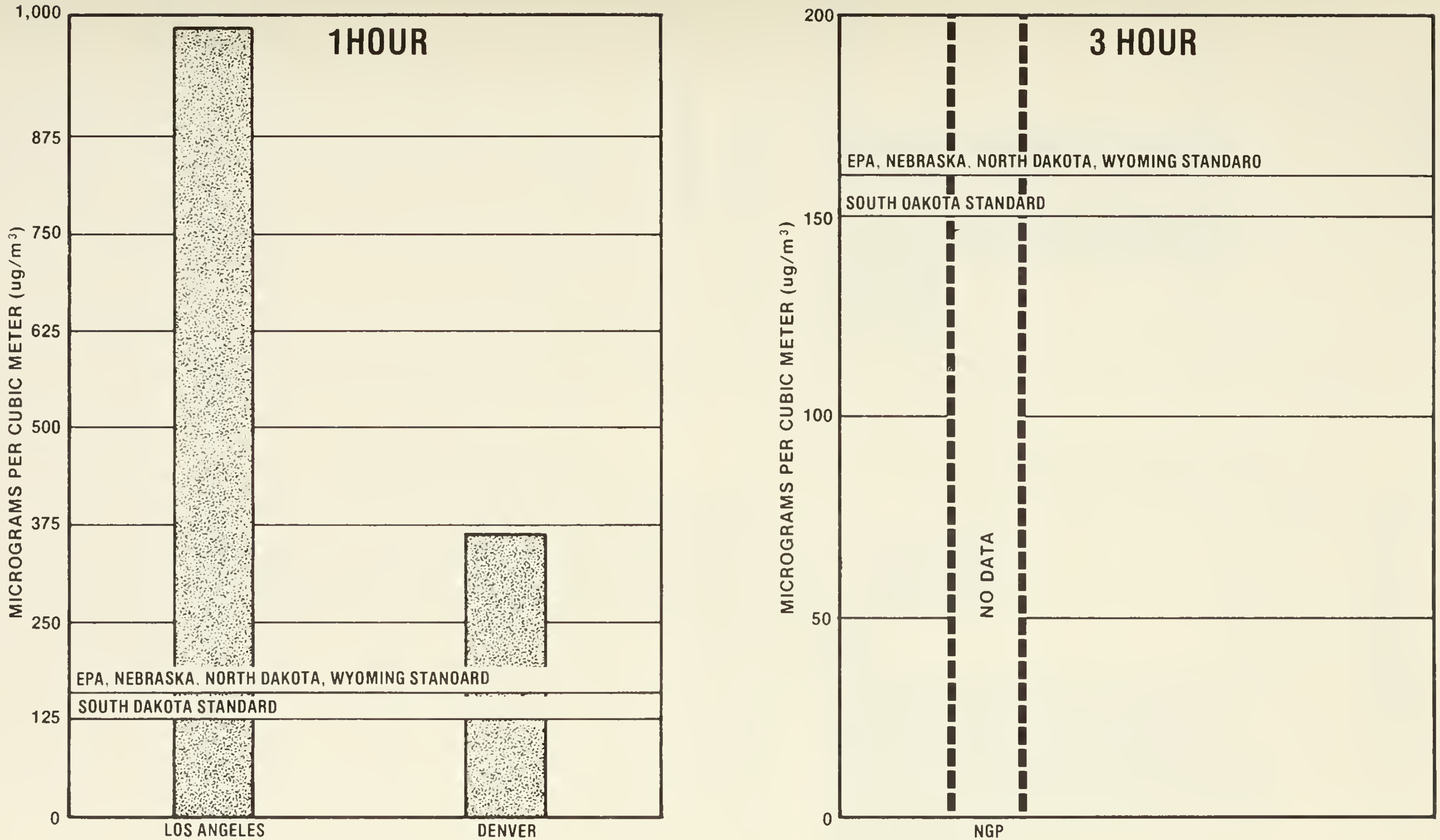


Figure 4-11. Nitrogen oxides—Ambient air quality data and standards.



Photochemical oxidants

Hydrocarbons

Figure 4-12. Photochemical oxidants and hydrocarbons ambient air quality data and standards.

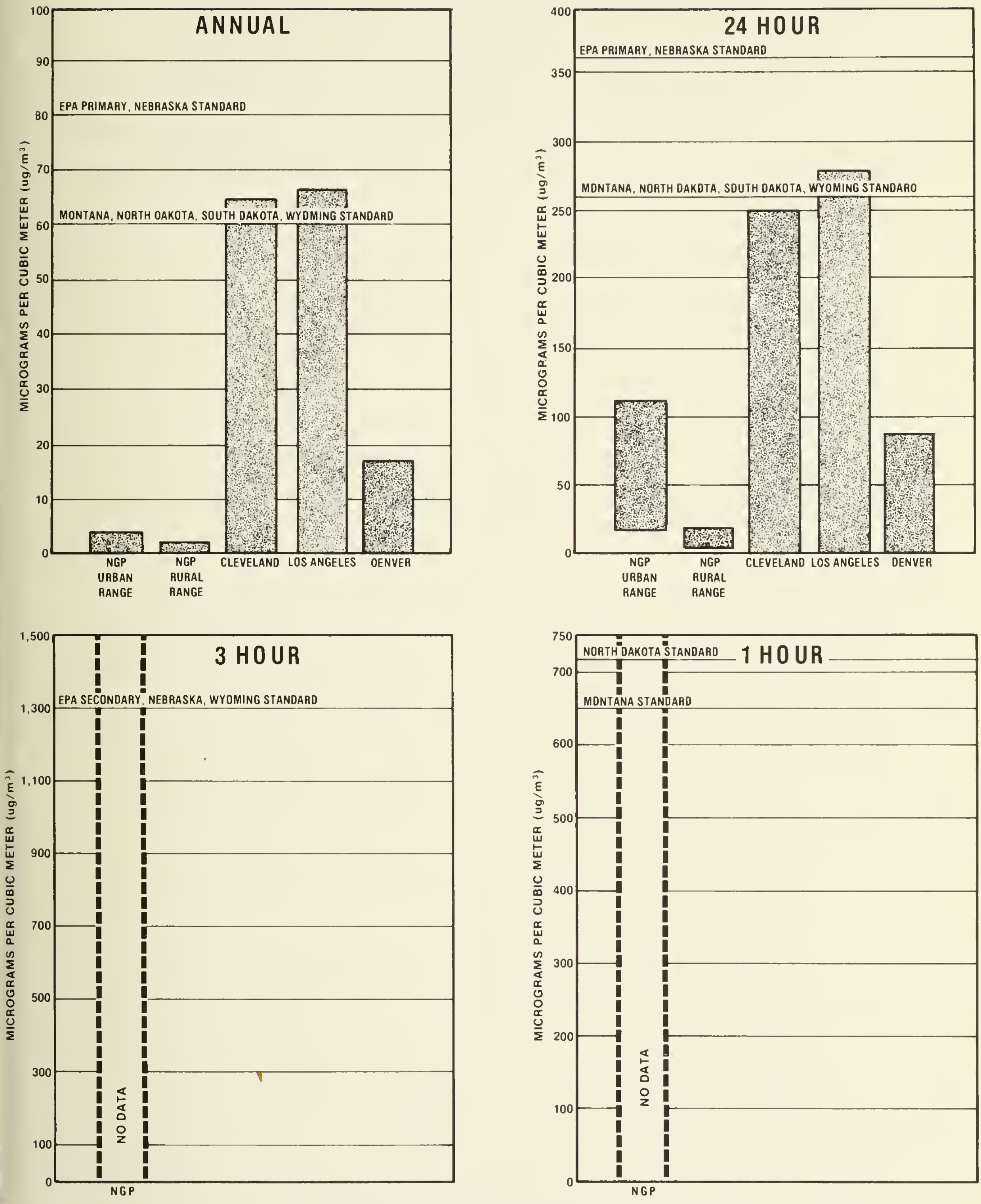


Figure 4-13. Sulfur oxides—Ambient air quality data and standards.

to be hydrocarbons with additional quantities of particulate, sulfur oxides, and nitrogen oxides from onsite steam generation. The potential harmful effects of these pollutants were recognized by Congress in passing various Federal Clean Air Acts. As a result of the 1970 Act, the Administrator of EPA promulgated primary and secondary standards (NAAQS) for the pollutants, that, in his judgment, have an adverse impact on health and public welfare. These standards are shown in table 4-27. Trace elements such as mercury, lead, beryllium, arsenic, flourine, cadmium, and selenium are emitted from coal conversion facilities. Chemical reactions which occur in the air result in the conversion of sulfur dioxide to sulfates (such as sulfuric acid) and nitrogen oxide to nitrates. Some of these elements or compounds can be harmful to human health, to animal and plant life, and to materials. There are no Federal standards applicable to coal conversion facilities for any of these pollutants at the present time. Some of the NGP states have standards for sulfates, lead, beryllium, and flourine.

In discussing the impacts of coal development on NGP air quality, a comparison to these standards will be made.

To attain and maintain the NAAQS a variety of State and Federal regulations on existing and new emission sources have been adopted. New NSPS (New Source Performance Standards) which are applicable only to new sources have been promulgated. Those standards (table 4-28) apply to all fossil-fuel fired steam generating plants larger than about 25 MW (megawatts) whose construction began after August 17, 1971 (lignite plants are exempt from the NO_x NSPS).

These standards would require a powerplant burning a 10 percent ash, 1.0 percent sulfur, 9,000-Btu-per-pound coal to control particulate emissions by 99 percent, sulfur oxide emissions by 40 percent, and nitrogen oxides emissions by 30 percent. Control of particulate matter may be achieved by highly efficient electrostatic precipitators, wet scrubbers, or fabric filters. Sulfur oxides emissions may be controlled via wet scrubbers using an alkaline media or via catalytic oxidation. Nitrogen oxides emissions are normally controlled by preventing the formation of NO by lowering the combustion temperature.

Existing sources of pollution in the states must meet regulations contained in SIP's (State Implementation Plans). The principal purpose of these plans is to attain and maintain ambient air quality standards.

There are three other related air quality standards which are relevant to this discussion. First, as part of the SIP process each state projects its anticipated emissions through the year 1985 and

Table 4-27.—*NAAQS (National Ambient Air Quality Standards)*

Pollutant	Primary standard	Secondary standard
1. Surfur oxides	80 ug/m³ (0.03 ppm) annual arith. mean 365 ug/m³ (0.14 ppm) max 24 hr. conc. not to be exceeded more than once a year.	1,300 ug/m³ (0.5 ppm) max 3 hr. conc. not to be exceeded more than once a year.
2. Particulate matter	75 ug/m³ annual geom. mean 260 ug/m³ max 24 hr. conc. not to exceeded more than once a year.	60 ug/m³ annual geom. mean*, 150 ug/m³ max 24 hr. conc. not to be exceeded more than once a year
3. Carbon monoxide	10,000 ug/m³ (9 ppm) max 8 hr. conc. not to be exceeded more than once a year.	Same as primary
	40,000 ug/m³ (35 ppm) max 1 hr. conc. not to be exceeded more than once a year.	Same as primary
4. Photo chemical oxidants (corrected for NO_2 and SO_2 interference)	160 ug/m³ (0.08 ppm) max 1 hr. conc. not to be exceeded more than once a year.	Same as primary
5. Hydrocarbons (corrected for CH_4)	160 ug/m³ (0.24 ppm) max. 3 hr. conc. (6 to 9 a.m.) not to be exceeded more than once a year.	Same as primary
6. Nitrogen oxides (as nitrogen dioxide)	100 ug/m³ (0.05 ppm) annual arith. mean.	Same as primary

*To be used as guide in assessing State Implementation Plans.

NOTE:

ppm = parts per million
ug/m³ = micrograms per cubic meter.

estimates air quality resulting from such projections. If the analysis shows that National Ambient Air Quality Standards may be exceeded, the state must develop a 10-year plan to insure that standards are maintained. Montana, North Dakota, and Wyoming have counties in the coal areas which are subject to these plans. Second, a Federal indirect source regulation has been promulgated and states are now in the process of adopting their own. The regulation requires evaluation of the impact of major highway proposals, airport proposals, and certain other facilities such as shopping centers, before an application to construct can be approved.

Table 4-28.–*NSPS standards*

	Allowable pounds/10^6 Btu		
	Coal	Oil	Gas
Particulate	0.10	0.10	0.10
SO_2(sulfur dioxide)	1.20	0.80	–
NO_x (oxides of nitrogen)	0.70	0.30	0.20

Lastly, the issue of air quality deterioration of clean air quality areas is being examined. The Clean Air Act of 1970, as amended, required a SIP to contain regulations to prevent significant deterioration where air quality is better than that required by the national standards. These regulations could be the single most important regulation both to the Nation and to the NGP in terms of maintaining excellent air quality. Present plans call for designating three types of geographical zones. The standards for these three zones are shown in table 4-29.

In Zone 1 there will be essentially no decrease in air quality allowed, in Zone 2 a moderate decrease will be allowed, and in Zone 3 the air quality can be degraded to the secondary standard.

Each state will be responsible for zoning itself and enforcing the standards. This means that the people of each state can maintain the quality of air however they choose as long as it does not threaten human health and welfare.

To estimate the effect of plant emissions upon present NGP air quality, pollutant concentrations were calculated using a computer model. The annual and 24-hour particulate, SO_2 (sulfur dioxide), oxides of NO_x (nitrogen), and HC (hydrocarbon) concentration estimates were made using a computer program similar to that published by Martin[11] (1971). Martin's program

[11] Martin, D., 1971, "An Urban Diffusion Model For Estimating Long Term Average Values of Air Quality" *J. Air Poll. Control Assoc.* 16, (1), pp. 16-19, January 1971.

was modified to Burt[12] (1973) to consider the effects of elevated terrain, to utilize Briggs[13] (1969, 1970, 1971, and 1972) plume rise equations, and to provide a significant computer printout which gives concentrations at specified grid points located along 16 radials fixed by the common 16 wind directions, N. NNE, NE, ENE, and so forth. A detailed description of the model as it has been modified, and the computer code is given by Burt[12] (1973). A complete description of the technique plus the assumptions are contained in the Atmospheric Aspects Work Group Report.[14] The estimates were based on powerplants that are either under construction, applying for construction permits, or are being proposed and have associated environmental studies in progress, and a hypothetical gasification plant. It was assumed that emissions from each powerplant would be equal to, but not exceed, NSPS. Emissions from the hypothetical gasification plant were estimated from data supplied by companies planning the construction of coal gasification facilities.

Table 4-29.–*Proposed significant air deterioration*

	ug/m³ increase over 1974 levels		ug/m³
	Zone 1	Zone 2	Zone 3
Particulate matter			
Annual	5	10	75
24-hour	10	30	150
Surfur oxides			
Annual	2	15	80
24-hour	5	100	365
3-hour	25	700	1,300

NOTE: ug/m³ is micrograms/cubic meter.

There, are no synthetic natural gas plants in existance or under construction in the United States at the present time. Therefore, emission estimates were obviously based upon design data only.

[12] Burt, E. W., 1973, "Description of Terrian Model (C7M3D)" (Manuscript in Preparation) MDAD, SRAB, Modeling Application Section, U.S. E.P.A., Research Triangle Park, North Carolina 27711.
[13] Briggs, G. A., 1969, "Plume Rise" U.S. A.E.C., *Critical Review Series TID-25075*, National Technical Information Service, Springfield, Virginia 22151.
[13] Briggs, G. A., 1971, "Some Recent Analyses of Plume Rise Observations", pp. 1029-1032, *Proceedings of the Section International Clean Air Congress* edited by H. M. Englund and W. T. Berry, Academic Press, New York City.
[13] Briggs, G. A., 1972, Discussion on Chimney Plumes in Neutral and Stable Surroundings, *Atmospheric Environment*, vol. 6, pp. 507-510, July 1972.
[14] *"Atmospheric Aspects Work Groups Report"* Northern Great Plains Resources Program, 1974, unpublished document.

The combined capacity of these plants (fig. 4-7) correspond closely to the CDP I, therefore impacts from these plants can be construed to be representative of CDP I impacts. That is the primary reason for the selection of these plants to be studied. Portions of these plants are operational today with the plant expansions being designed to become operational in the near future.

Table 4-30 presents the results of the modeling estimates for annual concentrations.

Table 4-30.–*Estimated annual air quality concentrations**

Plant	Maximum concentration, ug/m^3		
	Particulate	SO_2	NO_x
Colstrip	0.2	2.1	1.4
Naughton	0.7	8.2	6.0
	**6.0	**68	**50
Bridger	0.2	2.5	1.4
Underwood	0.04	0.4	0.4
Leland	0.03	0.5	0.3
Gentleman	0.04	0.5	0.3
Young	0.03	0.3	0.3
Wyodak	0.1	1.3	0.7

*Background pollutant concentrations not included.
**With terrain considered.

NOTE: ug/m^3 is micrograms per cubic meter.

Table 4-31 lists the "worst case" maximum predicted ground-level 24-, 3-, and 1-hour concentrations.

All of the concentrations listed in tables 4-30 and 4-31 are representative only of the contribution from the plant, that is, no existing pollutant concentrations (background) are included. Background must be added to obtain an estimate for comparison against relevant ambient standards.

Figures 4-14 and 4-15 illustrate the comparison between the applicable air quality standards and the estimated impact upon air quality as a direct result of the powerplant. It should be noted that these figures indicate the worst that could happen but do not include the frequency of occurrence of such an event. The probability of occurrence is determined by the frequency of occurrence of a given meteorological condition.

Table 4-31.–*Estimated short-term air quality concentrations**

Plant	Maximum 24-hour concentrations		Maximum 3- and 1-hour SO_2 concentrations	
	Particulate	SO_2	3-hour	1-hour
Colstrip	0.8	9	385	624
Naughton	0.8	10	270	440
Bridger	0.7	8	220	360
Underwood	0.4	5	120	194
Leland Olds	0.3	3	84	140
Gentleman	1.0	12	80	128
Young	0.4	5	170	278
Wyodak	0.3	3	125	200
Gasification plant	–	–	1,360 (Hydro-carbons)	–

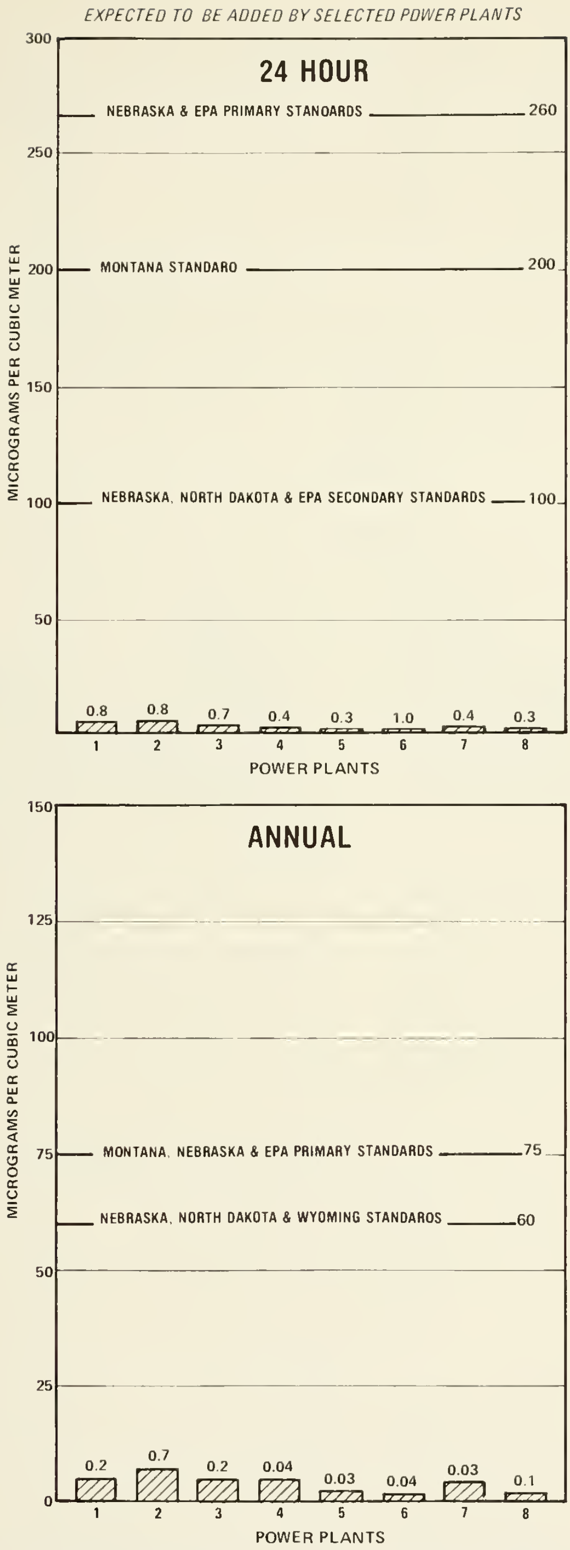
*All data in micrograms per cubic meter (ug/m^3).

The modeling analysis of the eight powerplants for SO_2 and particulates show that (fig. 4-14 and 4-15) no state or Federal standards will be violated.

The predicted annual average SO_2 concentrations in the vicinity of the Naughton plant approach the Wyoming and Federal standards. When corrected to Wyoming elevation, the 68 ug/m^3 (micrograms per cubic meter) concentration equates to about 55 ug/m^3. These values compare with the Wyoming standard of 60 ug/m^3 and the EPA primary standard of 70 ug/m^3.

It appears that there are three atmospheric conditions that may result in conditions that could violate standards. The first situation occurs when there are extremely stable atmospheric conditions with steady winds for 8-10 hours directing the plume toward elevated terrain. This causes the pollutants to impinge at the elevated point thus causing a possible violation. The second condition, termed fumigation, occurs when there are extremely stable conditions that result in a localized build-up of pollutants above the earth's surface followed by a rapid change to an unstable atmosphere which would cause these pollutants to settle on the earth's surface. The third condition is when extremely unstable wind conditions exist and the plume is directed to the ground very near the point of emission. Available meteorological data for the sites studied indicate that these conditions occur very infrequently and they may not persist for sufficient duration to cause a violation of a standard.

Diffusion modeling provided air quality estimates of about 800 ug/m^3 (micrograms per cubic meter) and a 3-hour hydrocarbon concentration associated with the gasification plant. This value



1. COLSTRIP – 2060 MW
2. NAUGHTON – 1570 MW
3. BRIDGER – 1500 MW
4. UNDERWOOD – 972 MW
5. LELAND OLDS – 656 MW
6. GENTLEMAN – 650 MW
7. YOUNG – 635 MW
8. WYODAK – 330 MW

Figure 4-14. Maximum ambient particulate concentrations.

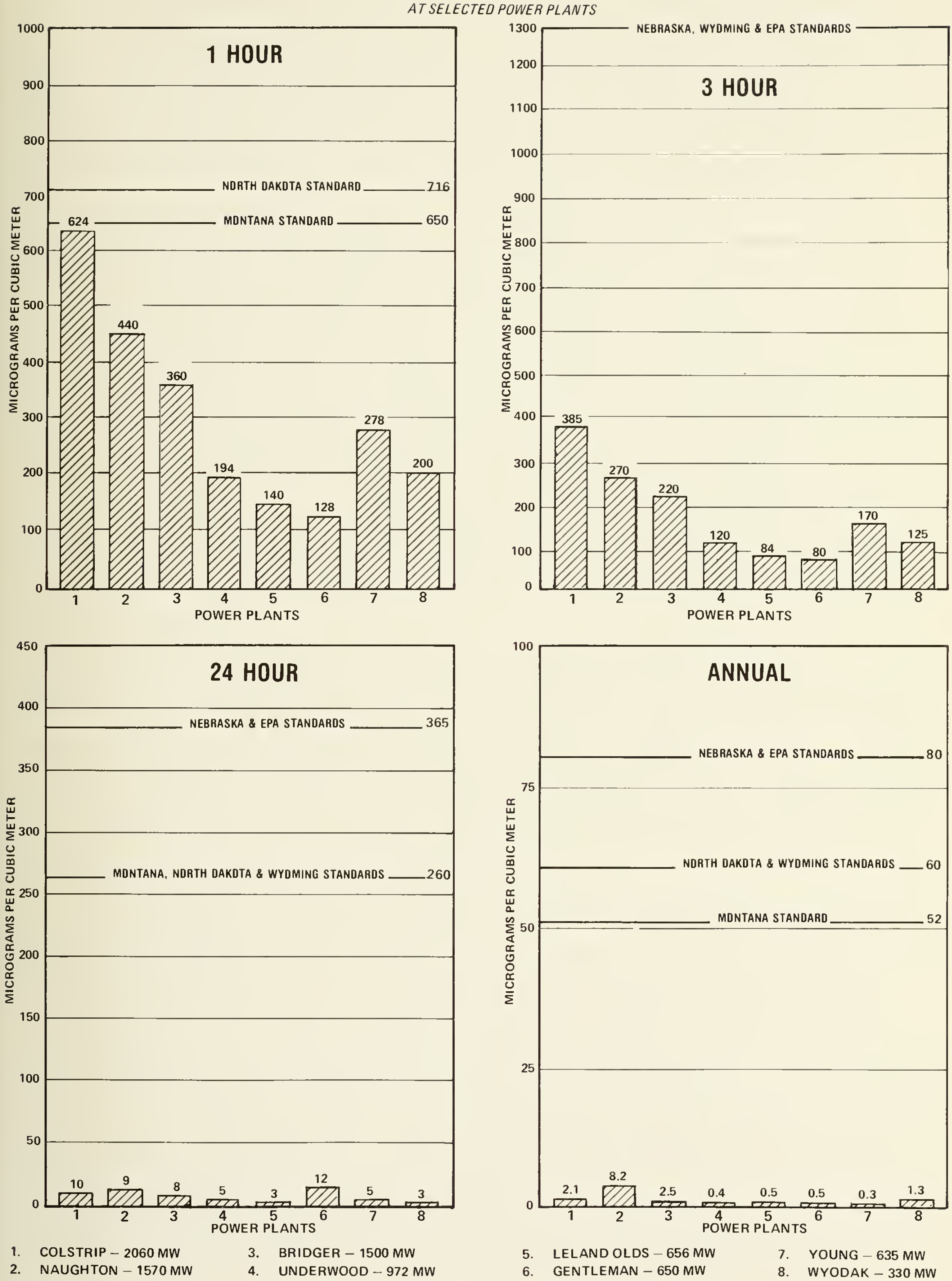


Figure 4-15. Maximum ambient SO_2 concentrations.

is well over the allowable standard of 160 ug/m^3. Therefore, the proposed gasification plants will have to control their hydrocarbon emissions to a further degree than preliminary planning would indicate. This control can be accomplished by incineration, adsorption, absorption, or catalytic conversion. Draft environmental impact statements that have been released indicate that hydrocarbon emissions will make essentially no contribution to air quality concentrations.

An estimate of the pollutant concentrations compared to standards was not made for specific plants in either medium or high CDP's because of a lack of specific plant data and sites specific meteorological data. An air quality and meteorology monitoring network has been established to compliment the existing data gathering efforts. Monitoring is being conducted at 22 new sites in the region in addition to the 30 sites presently existing. This new data, combined with existing regional meteorological data gathering activities, will enable the use of a regional model approach which is necessary to assess the interactions of several plants upon some remote area.

Although modeling was not performed, the pollutant emissions introduced into the atmosphere by power and gasification plants at each of the three CDP levels for five pollutants was estimated. Table 4-32 lists those emissions. For comparison purposes, refer to the previously presented emissions in table 4-26.

(b) *Secondary Impacts.*–Only the direct environmental impacts of the coal conversion facilities were factored into the modeling effort. Secondary impacts may have a significant impact upon air quality. Mining activities and the attendant population growth are the major identifiable "secondary impacts." It is extremely difficult to quantify secondary impacts. However, work is being done to provide data which may enable quantitative assessment. Only a qualitative discussion may be presented at this time.

It is known that an increase in particulate matter, in the form of fugitive dust, will occur as a result of any strip-mining activity. Also because of the activities of people required to support the coal conversion facility, there will be an increase in emissions resulting from their activities.

The effect of the increased atmospheric loadings of particulate matter, especially the significant increase in fine particles and gaseous pollutants, upon visibility is extremely difficult to predict. It is logical to postulate that a decrease in visibility will occur, but the extent of that reduction cannot be quantified with our present data. It is the fine particles, such as those in the 0.1 to 1.0 micron (radius) size range, that dominate the light scattering phenomenon and hence degradation of visibility. This is the size of particulates that will be emitted to the greater extent

because most present day pollution control techniques are relatively inefficient collectors of submicron particles.

Table 4-32.—*Estimated emissions from projected coal conversion facilities in tons per year*

	Powerplants			Coal gasification plants		
	Low CDP	Intermediate CDP	High CDP	Low CDP	Intermediate CDP	High CDP
Particulate						
1985	41,700	41,700	41,700	0	13,370	38,200
2000	99,330	142,180	142,180	0	30,560	78,310
Sulfur oxides						
1985	500,600	500,600	500,600	0	150,710	430,600
2000	1,192,750	1,707,240	1,707,240	0	344,480	882,730
Nitrogen oxides						
1985	291,850	291,850	291,850	0	72,520	207,200
2000	695,330	995,260	995,260	0	165,760	424,760
Hydrocarbon						
1985	8,780	8,780	8,780	0	609,490	1,741,400
2000	20,910	29,930	29,930	0	1,398,120	3,569,870
Carbon dioxide						
1985	29,620	29,620	29,620	0	5,320	15,200
2000	70,570	101,010	101,010	0	12,160	31,160

About 431,000 tons of particulates are presently emitted each year in Montana, North Dakota, and Wyoming. The low, intermediate and high CDP's would increase this loading by 18, 31 and 42 percent, respectively, by the year 2000. The coal bearing area, however, is much smaller than the three states and the increased loading would be many times what is not introduced into the area. The degree to which the plants were concentrated would have a strong influence on the reduction of visibility. After data now being collected are analyzed, the extent to which the problem could be reduced, can be better estimated.

(c) *Potential Constraints to Coal Conversion.*—Present law requires that ambient air quality standards must be attained and maintained throughout the NGP. Air quality impacts as a result of the construction of powerplants at the CDP I level would appear not to affect maintenance of the standards. However, some possible interpretations of the "significant deterioration" issue

would constrain development. Plant sitings, plant size, and degree of emission control may be influenced by this resolution.

Technology for control of hydrocarbon emissions from gasification plants must be improved if hydrocarbon air quality standards are to be maintained. The degree of the control technology will be one factor in the determination of the extent of development.

Development at CDP II and III levels may be constrained by air quality standards.

4-14. *Research and Analysis Needs.*—Some research needs are necessarily regional in nature while others have national impacts. It is anticipated that through the NGPRP some data may be collected to provide input to those national needs.

The significant increase in SO_2 emissions, hence atmospheric loadings, creates the potential for a decrease in the pH, that is, the measurement of acidity of rainfall in the Northern Great Plains and midwestern states. The amount of this pH decrease cannot be determined with any degree of accuracy on a theoretical basis without making a wide set of assumptions. Measurement of pH at a number of rain collection stations in the NGP should be initiated. In so doing, baseline data may be gathered with subsequent measurements identifying the impact of the projected coal conversion facilities. This is potentially serious because should the pH drop significantly, acid rains could be created with many associated corrosive and health impacts.

The potential for photochemical oxidant formation in the vicinity of coal gasification complexes appears to be significant. These oxidants are serious in causing eye irritation, pulmonary tract damage, and a deleterious affect on vegetation. The Los Angeles-type brown smog is a case of photochemical oxidant formation. The combination of hydrocarbon emissions from the gasification process, the nitrogen oxides emission from the attendant steam generating plant, and a high frequency and intensity of sunlight in the NGP states provides all the ingredients for potential oxidant formation. A network of hydrocarbon, NO_x and oxidant ambient air quality monitors should be established in the areas of potential gasification plants to obtain baseline data. An ongoing network of oxidant monitoring should continue well into the future to determine the impact of the anticipated facilities.

Effects of the pollutants for which there are Federal standards and of trace pollutants from coal conversion facilities upon young vegetation in reclaimed areas should be evaluated. A research study being cônducted by the National Environmental Research Center at Corvallis, Oregon, will address this topic to a certain degree. More effort should be directed toward this activity.

The aspect of the increased particulate matter in the atmosphere acting as additional cloud condensation nuclei should be studied. Both increased and decreased precipitation have been theorized as a result of this phenomenon. This is important because of its potential for regional climatic change.

The atmospheric concentrations and effects of increased CO_2 (carbon dioxide) emissions should be evaluated. Monitoring sites could be identified where CO_2 levels would be measured over a long period of time. This is one of the causes of the theorized world-wide "greenhouse effect."

Health and welfare effects of increased atmospheric loadings of sulfates and nitrates should be studied. A program similar to the Community Health Environmental Surveillance Study might provide beneficial information. Sulfates and possibly nitrates are being shown to have serious health effects on humans and animals.

The increased levels of fine particulate matter in the atmosphere and the potential light attenuation and solar insolation effects should be the subject of further in-depth research. There is not sufficient information available to predict how serious the reduction in visibility would be and there is insufficient knowledge on potential regional and world-wide climatic changes.

The identification of the fate of trace elements during the combustion of coal is being studied. Much more work needs to be done on this to determine their potential impacts and to determine the presence and concentrations of trace elements in the coal throughout the NGP. This could be very important in determining which coals should be mined to minimize trace element pollution.

There are preliminary indications that trace elements tend to be preferentially concentrated in the smaller particle size range. If this is so, then the health problems caused by small particulates may be even more serious than anticipated. A theory of volatilization and subsequent adsorption onto the small particle surface area has been put forth as an explanation. Almost no extensive studies have been performed on this topic, but they are needed.

PART V—THE ECONOMIC, SOCIAL, AND CULTURAL IMPACTS OF COAL DEVELOPMENT IN THE NGP

5-1. *Introduction.*—Coal development may have a profound impact upon the economy, institutional fabric, and social structure of the residents in the Northern Great Plains. It is an extremely difficult task to accurately assess what impact coal development will have upon the people of the Northern Great Plains. Some impacts are quantifiable, while others can only be addressed subjectively. It is in this framework that the economic, social, and cultural impacts are addressed.

Some of the issues to be discussed in this section are:

—How will coal mining and conversion change the employment patterns and levels in the NGP?

—How much and how fast will the population of the region grow?

—How will the population increases effect the availability of housing, educational facilities, and municipal services?

—What tax revenues will be generated by coal development and will they be available in sufficient amounts to meet the needs of local and state governments?

—How will coal development effect the agricultural industry?

Impacts stemming from increased coal development will touch nearly every sector in the NGP study area, be it the economy, government institutions, or the social system. Coal development will affect the economy by creating new and expanded job opportunities as well as higher levels of income in the region. Population growth associated with coal development will mean unprecedented population increases, both in terms of magnitude and the speed with which it will occur. Also, the ability of the present institutional structures will be severely tested. Higher levels of service will be required as well as new services to meet the demands of the existing and new population. Complicating the increased institutional demands is the potential of time lags between when services are needed and new revenues. Social systems will be altered and strained as new value systems and new peoples are imposed upon a well-established social system. Conflicts and increased social tensions may occur.

Coal development is a regional problem as it will affect individuals and localities over a wide geographic area. Nonetheless, it is the local people and institutions which will have to address this

problem and resolve the issues. Although each community must assess its own special problems it is doubtful if many of the localities in the Northern Great Plains are really prepared or capable of accomplishing the task.

Considerable uncertainty remains regarding the socio-economic impacts of coal development in the Northern Great Plains. Because of the complex nature of coal development, it is extremely difficult to estimate or assess cumulative impacts. However, these impacts may be critical. Is the impact of two mines or powerplants in the same area twice as great as the impact of one, or is it larger? Furthermore, how adaptable is the socio-economic environment? Do equal increments of change require equal adjustments or do they require successively more? It is quite possible that the impacts of coal development in the Northern Great Plains may be greater than the projection and analytic techniques used have been able to delineate.

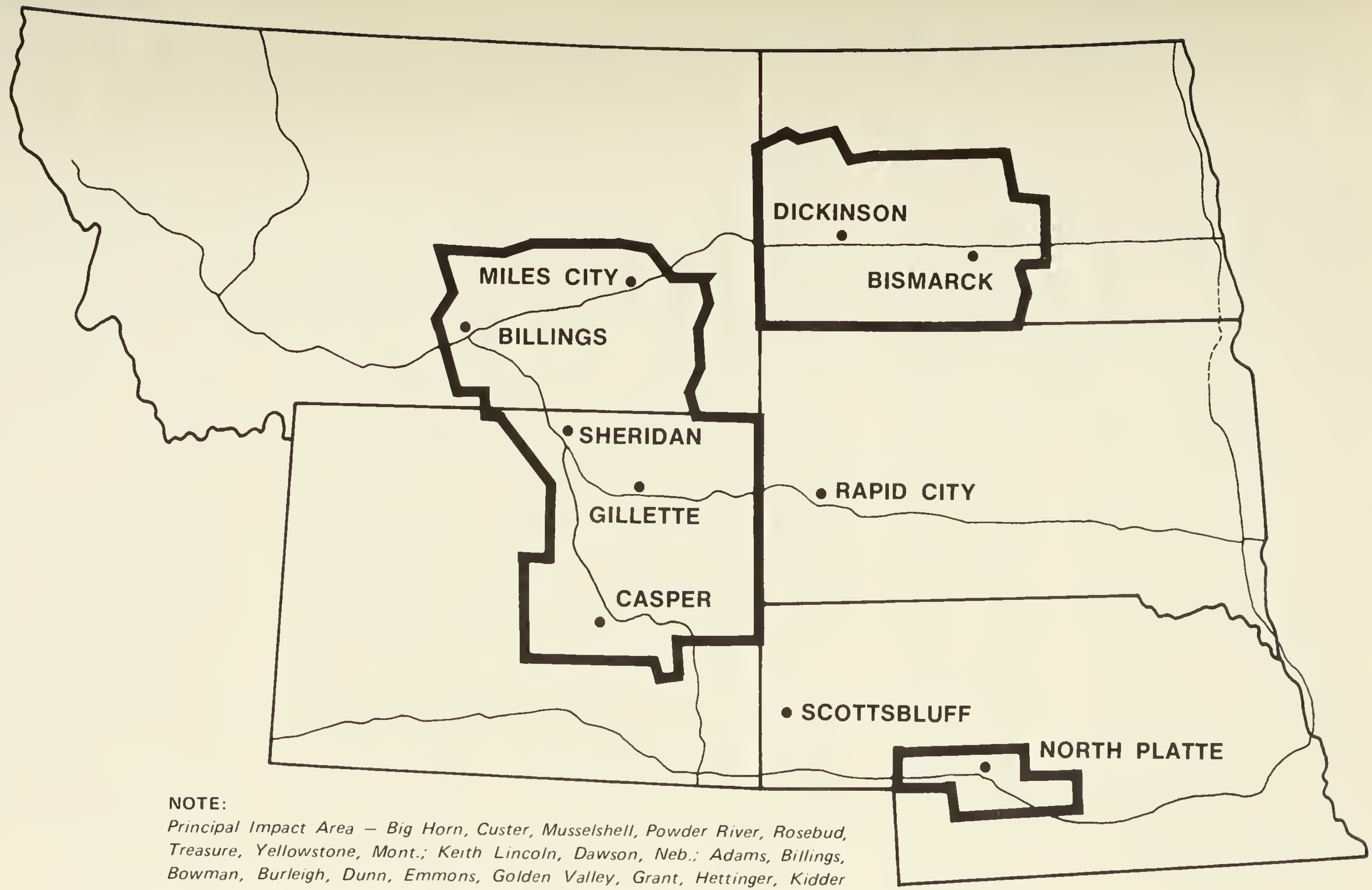
From within the states of Wyoming, Montana, North Dakota, and Nebraska, 36 counties were selected as the "principal impact areas," (see fig. 5-1). Similiarly, from within these impact areas a number of communities were designated as "principal impact communities." Common to both these "areas" and "communities" is the fact that they contain the heaviest concentration of present and proposed coal development activity. Consequently, they will receive the heaviest concentration of impacts generated by such activity.

Many Indian reservations will be affected by coal development. Some contain considerable amounts of coal and some is already leased. Consequently, potential coal development impacts on Indian peoples was also selected for more detailed analysis.

The one economic activity having the longest tradition and widest influence in the four-state study area is agriculture. Therefore, it too was selected for consideration of the impacts imposed by coal development. Within agriculture, labor, water, and land were selected as the most meaningful expressions of impact.

Appropriate economic indicators that were selected for measurement of change within the "impact area" and "impact communities" included employment, population, education, and housing. These are discussed in the report.

The intent here is to indicate, on a sample basis, the kind and magnitude of changes that coal development may be expected to generate. It is assumed that additional studies that are more site-specific, more precise, and more definitive will be needed to support land use planning and decisionmaking. Some examples of such follow-up studies also are given.



NOTE:
Principal Impact Area – Big Horn, Custer, Musselshell, Powder River, Rosebud, Treasure, Yellowstone, Mont.; Keith Lincoln, Dawson, Neb.; Adams, Billings, Bowman, Burleigh, Dunn, Emmons, Golden Valley, Grant, Hettinger, Kidder McLean, Mercer, Morton, Oliver, Sheridan, Sioux, Slope, Stark, N.D.; Campbell, Converse, Crook, Johnson, Natrona, Niobrara, Sheridan, Weston, Wyoming.

Figure 5-1. Northern Great Plains states, principal impact area and major cities.

5-2. *The Principal Impact Area and Changes Expected as a Result of Coal Development.*—(a) *Employment.*—Employment projections[1] for the principal impact area within the states of Wyoming, Montana, Nebraska, and North Dakota are summarized in table 5-1. The increase in employment in these four states between 1970 and 2000 ranges from 28 percent for CDP I to 143 percent for CDP III. Total employment under CDP III increases by 148 percent within the principal impact area in Wyoming, 159 percent in Montana, 172 percent in North Dakota, and 32 percent in Nebraska.

In the coal sector specifically (table 5-2), total coal-related employment under CDP I would be 17,000 in 1980, fall to 8,000 by 1985, then climb to 18,000 by year 2000. Approximately 60 percent of the total direct employment would be operational and 40 percent construction-related employment.

Under CDP II, 23,000 people would be employed in coal-related jobs in 1980 and 85,000 by the year 2000. Approximately the same percentage of direct to indirect employment would be expected as in CDP I; 2,000 direct operational jobs and 4,000 construction jobs in year 1980 and 19,000 operation and 5,000 construction jobs by the year 2000.

Under CDP III, employment would substantially increase; 84,000 people would be working in coal-related activities in 1980 and 175,000 by year 2000. Direct operational employment would total 10,000 in 1980 and increase to 49,000 by year 2000, while construction employment would total 16,000 in 1980 and decrease to 9,000 by year 2000.

As noted here, growth from operational employment will be strong but reasonably stable over the period of development, while construction employment will fluctuate considerably. Large construction forces will swell the population in impacted areas, peak, and then decline to zero. An example of this wide fluctuation in construction employment is presented in figure 5-2 for Campbell County, Wyoming.

As an indication of the employment that would stem from coal development, in CDP III agriculture[2] would no longer be the principal basic employment sector in the area. Coal would become the dominant sector in both Wyoming and Montana, overshadowing agriculture and petroleum in Wyoming and agriculture and manufacturing in Montana. In CDP I and II, coal employment would be expected to remain below agriculture employment.

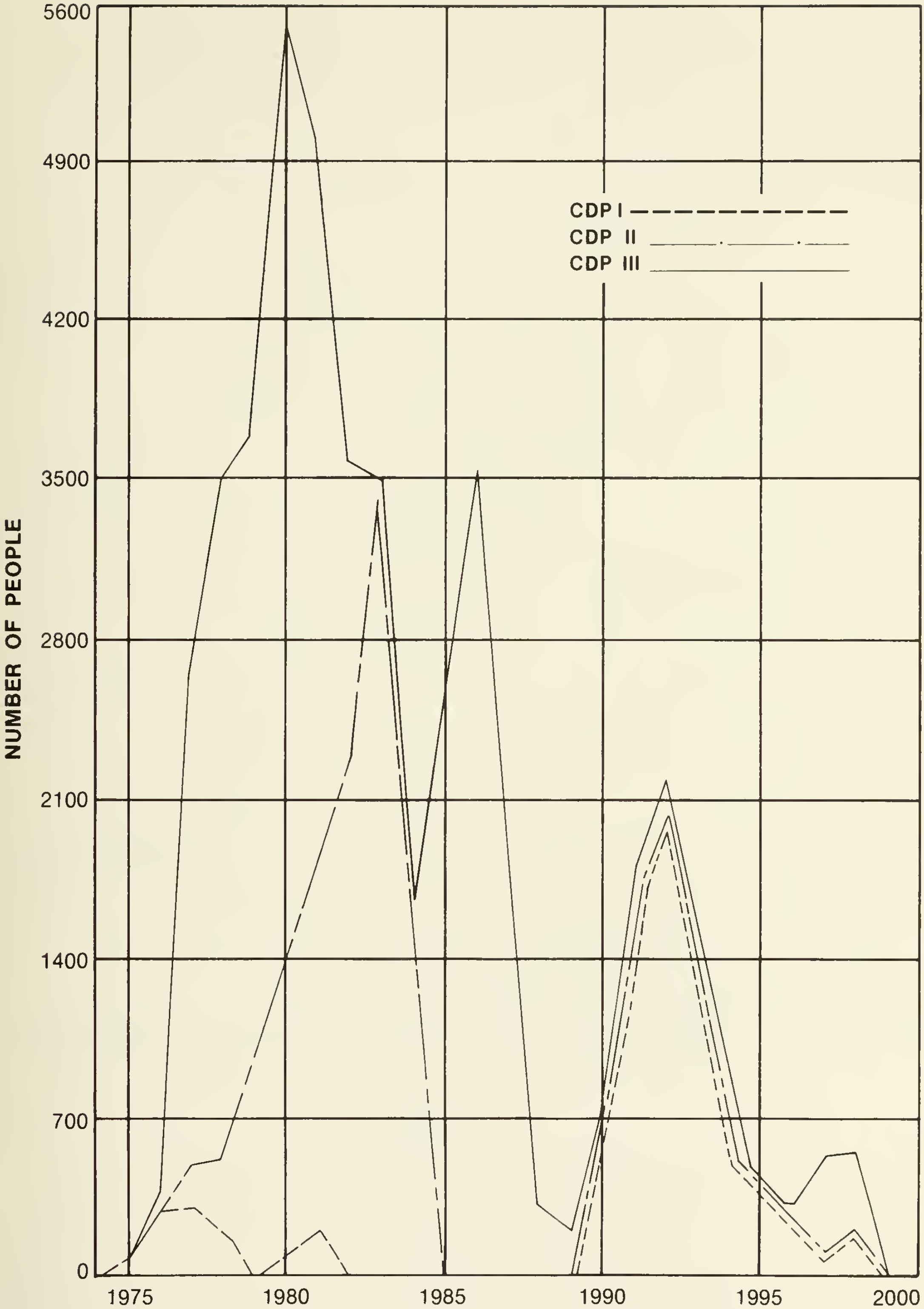
[1] The estimates presented reflect direct and indirect service employment for the operational as well as the construction phase of development. Employment that would be created by satellite industries that might locate near large gasification or powerplants is not included. Therefore, the estimates are conservative. No employment projections for South Dakota are presented because the selected principal impact areas did not involve South Dakota.

[2] Although agriculture presently is the primary source of basic employment in the four states, it is declining in its relative importance. During the decade from 1960-70, total agricultural employment declined by more than 30 percent in the four-state area. In other industrial sectors, mining gained 3 percent while manufacturing increased by more than 12 percent.

Table 5-1.*Total employment–principal impact area 1970-2000*

	1970	1980	1985	2000
		All units in thousands		
Montana	46	56	53	63
North Dakota	53	60	55	64
Wyoming	42	48	51	54
Nebraska*	22	26	27	29
Total	163	190	186	209
		CDP II		
Montana		57	75	80
North Dakota		60	71	105
Wyoming		52	59	67
Nebraska*		26	27	29
Total		195	235	281
		CDP III		
Montana		76	88	119
North Dakota		90	82	144
Wyoming		57	78	104
Nebraska*		26	27	29
Total		249	275	396

*The same figures were used for Nebraska in all profiles.



Source: Bureau of Reclamation (1974)

Figure 5-2. Estimated annual average construction employment during construction of facilities for mining, electrical plants, and gasification plants, Campbell County, Wyoming 1975-2000

Table 5-2.–*Estimated employment related to coal development (principal impact area–CDP's I, II, and III)*

Area	CDP I			CDP II			CDP III		
	1980	1985	2000	1980	1985	2000	1980	1985	2000
	(All units thousands)								
MONTANA:									
Direct operating	1	1	2	1	4	6	4	7	14
Construction	1	–	1	1	3	1	4	3	2
Indirect	7	3	7	7	20	17	22	26	40
Total	9	4	10	9	27	24	30	36	56
NORTH DAKOTA:									
Direct operating	1	–	1	*	3	9	5	7	20
Construction	1	–	–	1	3	4	7	3	7
Indirect	4	1	3	4	12	32	24	19	57
Total	6	1	4	5	18	45	36	29	84
WYOMING:									
Direct operating	1	1	1	1	2	4	1	7	15
Construction	–	–	–	2	1	–	5	3	–
Indirect	2	2	3	6	9	12	12	24	20
Total	3	3	4	9	12	16	18	34	35
STATE TOTALS (Principal impact area)									
Direct (operating and construction)	4	2	5	6	16	24	26	30	58
Indirect	13	6	13	17	41	61	58	69	117
Total	17	8	18	23	57	85	84	99	175

*Where estimates are less than 500 they are not shown. Nebraska estimates were never greater than 500; therefore, estimates for this State were not included in this table.

Figure 5-3 illustrates the relative magnitude of change in agriculture employment relative to coal-related employment in the CDP's. The effects that coal development might have on agricultural employment is not portrayed in this illustration, that is, agriculture employment is assumed to be the same for each CDP.

(b) *Population.*—Population projections in the principal impact area are summarized by year and CDP in table 5-3. The total population growth for this area between 1970 and 2000 ranges from 19 percent for CDP I to 119 percent for CDP III. Under the assumptions of CDP III, the population of the principal impact area will increase from 434,000 to 950,000 between 1970 and 2000. This would be in marked contrast to the population growth of only 1 percent experienced in this area during the decade of the 60's.

As the data presented in table 5-3 suggests, only a small increase in population in the principal impact area is expected to occur in CDP I. Although growth of approximately 5 percent would be experienced between 1980 and 2000, most of it is expected to result from noncoal sources, since very little expansion of coal mining is assumed after 1980. Consequently, the area should return to its historically modest rate of growth after 1985.

In CDP II, population would escalate to approximately 679,000 by year 2000, representing an increase of 56 percent over the impact area's 1970 population. Several factors would account for this rather significant growth rate. The principal reason is that CDP II assumes substantially greater coal mining beyond the CDP I level for the impact area. In addition, coal gasification is introduced in this profile as a source of employment and economic growth. As a result of this, and increased coal export, a substantial increase in construction and operating employment and associated population growth can be expected.

This, however, is relatively small when compared to the population growth that would occur under CDP III. In this profile, a significantly greater number of coal gasification and export coal mines are assumed. As a result, population in the principal impact area would be expected to increase by over 100 percent during the 30-year period between 1970 and year 2000.

Although the CDP's assume that new facilities come on line throughout the study period, growth rates in the principal impact areas will vary depending upon the scheduling of coal-related developments (see fig. 5-4). For instance, Wyoming, under CDP I, has a projected growth in population of 17,000 between 1970 and 1980, and only 8,000 from 1980 and 2000. North

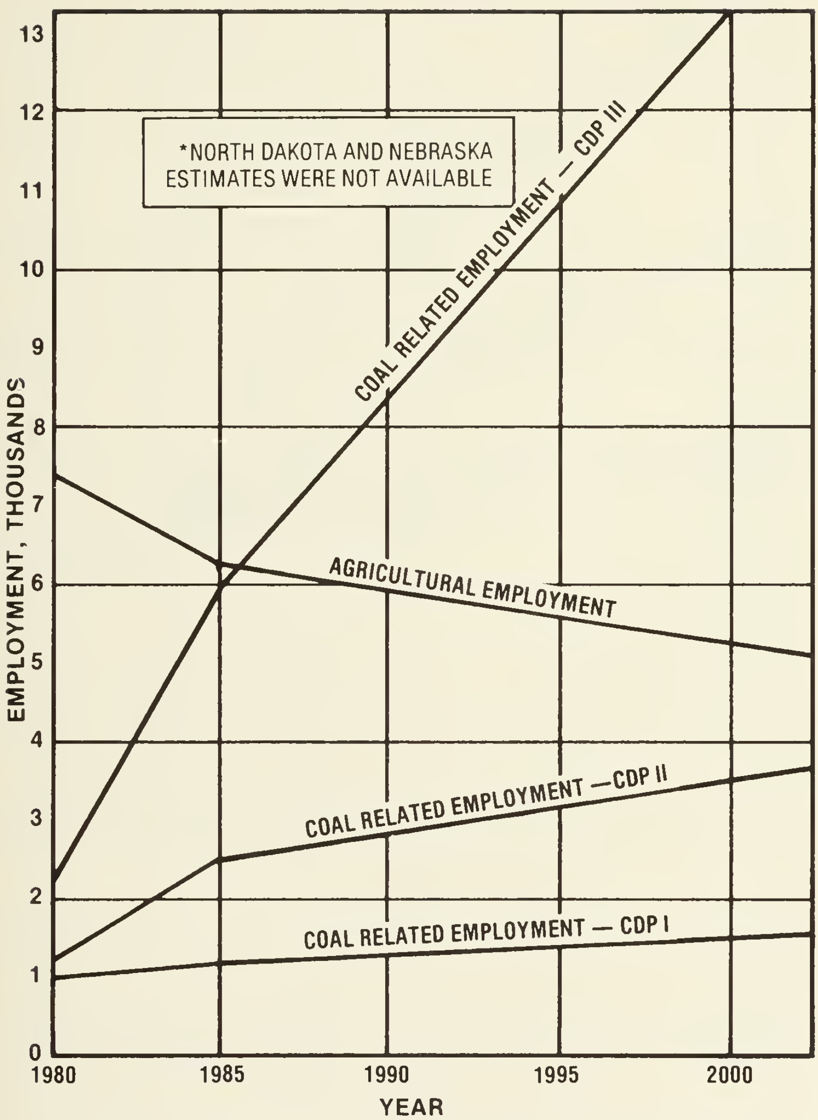


Figure 5-3. Coal-related employment as compared to agricultural employment principal impact area-Montana and Wyoming* 1980-2000

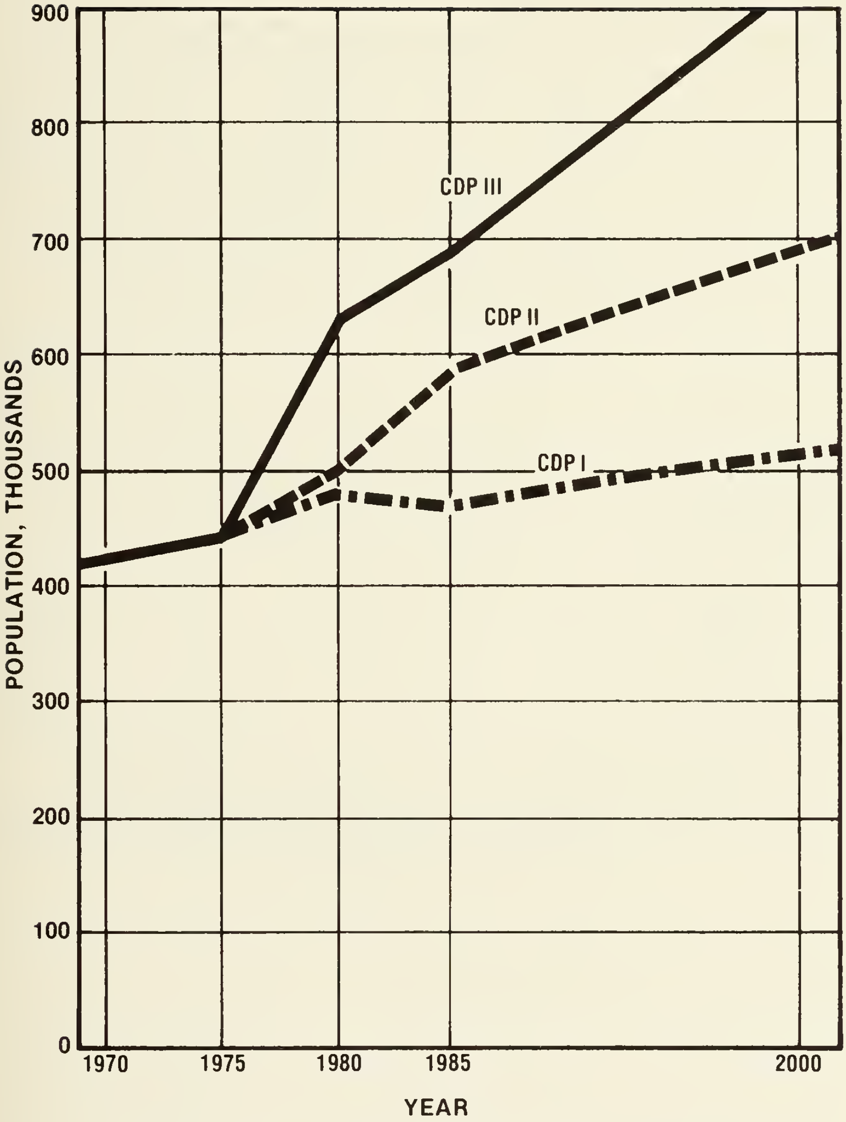


Figure 5-4. Anticipated population in the study area for each CDP.

Table 5-3.—*Total population projections, CDP I, II, III—1980, 1985, 2000*

	State totals 1970	Principal impact area			
		1970	1980	1985	2000
	All units thousands				
CDP I					
Montana	694	123	142	135	157
North Dakota	618	147	163	145	162
Wyoming	332	107	124	128	132
Nebraska*	1,483	57	61	62	65
Total	3,127	434	490	470	516
CDP II					
Montana			144	179	187
North Dakota			163	188	267
Wyoming			131	145	160
Nebraska*			61	62	65
Total			499	574	679
CDP III					
Montana			180	203	267
North Dakota			243	217	386
Wyoming			140	181	239
Nebraska*			61	62	65
Total			624	668	950

*Identical figures are shown for Nebraska in all profiles because any changes between CDP's are so small that the differences are negligable in rounding.

Dakota, because of a projected decrease in construction employment under CDP's I and III, can be expected to experience a population decrease between 1980 and 1985 with expansion continuing until 2000 but at a much slower rate.

The economic and social consequences of population changes are discussed in the remaining portions of part V.

(1) *Migration.*—Low population growth rates in the principal impact areas can be reasonably explained by the region's migration pattern. In the recent decade—1960 to 1970—45,000 people migrated from the principal impact area. This represents a 10 percent net emigration rate for the 10-year period. North Dakota lost the greatest number of inhabitants (27,000) followed by Montana (8,000), Wyoming (6,000), and Nebraska (4,000).

What can be expected in the future is unclear.

There are a number of considerations regarding migration that cannot be treated adequately at this time, such as:

—Sources of labor both from within and outside the area.

—Wages necessary to attract workers.

—Competition for labor and the effects stemming thereform.

—Socio-economic characteristics of prospective immigrants.

—Working conditions at the plants and mines, and

—Numbers of people leaving area because of social and economic dislocation.

There are indications, however, that only a small labor pool exists within the principal impact area. A large number of workers may be induced to migrate into the area and reverse the historic trend of net emigration. Although the level of migration depends upon the magnitude of development, which varies greatly between CDP, a net increase should occur by 1980 in the principal impact area.

(2) *Spatial distribution.*—Coal development is expected to occur at a significant level in only a few of the counties within the principal impact area. Therefore, impacts will be concentrated in only a few key locations and not spread evenly over the area.

The most obvious example of this occurs in Wyoming. Under CDP III in year 2000, Campbell County is expected to experience an increase in population of about 64,000, or nearly 500 percent. During the same period, Niobrara County, a neighbor to the southeast, is projected to experience a decline in population of about 14 percent.

The isolation of some of the plant and mine locations from urban centers coupled with their ultimate size[3] raises the possibility of new town developments. Commuting could pose a problem in coal development areas like those envisioned in Wyoming where plant and mine sites are located in excess of 40 miles from Gillette, the only urban area in the county.

5-3. ***The Principal Impact Communities and Changes Expected From Coal Development.***—Communities within the principal impact areas range from small towns of less than 100 people to a few cities[4], the largest of which is Billings, Montana, with a population of over 61,000. The typical size of towns in the area ranges between 500 and 3,000, with some villages having populations of less than 20. Villages of this size would probably only have a post office that serves the farm or ranch community surrounding it and a service station for tourists traveling through the area.

The somewhat larger towns may have a school, post office, and a small business center which may consist of only a grocery and hardware store. Little else would be provided leaving the residents of these communities heavily dependent upon the larger trade and service centers, for example the county seat towns, to satisfy a large portion of their needs.

Communities, such as Forsyth, Gillette, and Stanton, have been capable of providing most of the service needs of the people within their respective area of influence. Services provided include such facilities as churches, a hospital with small staff, secondary wholesale units, and a daily or weekly newspaper. Additional services include gasoline service stations, eating and drinking establishments, clothing and food stores, repair facilities, movie theaters, and barber shops. A variety of professional services including those of optometrists, dentists, and veterinarians generally have been provided.

Many services are provided by nonprofit organizations, such as hospitals, social welfare services such as charity, counseling, religious instruction, citizen action, Junior Chamber of Commerce, youth groups, and other groups.

Governmental services provided include police and fire protection, education and welfare, sanitation, sewage, as well as parks and recreation facilities.

The large urban centers like Billings, Rapid City, and Bismarck offer a wide range of goods and services and act as wholesale suppliers to the smaller trade centers.

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[3] A single gasification complex of the size envisioned in this study could induce a population of as many as 7,000 people which is about the 1970 population of Gillette.

[4] Other large communities in the principal impact area and their 1970 populations include Bismarck (34,290) and Casper (39,361).

To finance their public service systems, the communities rely principally upon the property tax which is levied and collected by the local governments. Floating revenue bonds or selling municipal water are other ways to generate revenues but they are methods generally reserved for the larger cities. A small amount of revenues accrue to the local governments in the form of reapportioned state tax revenues, but these are generally small and vary considerably with the type of tax levied and the individual state tax structure. In addition, revenue sharing is a new source of revenues for local governments—two thirds of a state's revenue sharing allocation is apportioned to units of local governments.

As opposed to the rather limited means of financing available to town and city governments, state and county governments have a variety of methods that can be used to secure revenues to finance their operations. Taxes provide the largest share of state revenues which, to reiterate, are reapportioned, in part, back to local levels of government. The types of taxes and the levels of government to which they are distributed are presented in table 5-4.

State revenues are also derived from State and Federal leasing and royalty payments, Federal assistance programs (including revenue sharing), and Federal grants.

In Wyoming, the royalties paid to the State from production of minerals on State lands go to the permanent fund, while Federal mineral royalties are used only for roads and schools. In Montana, the State share of Federal leasing and royalty revenues is divided equally between the highway and school fund, while State leasing and royalty revenues go to the State school trust. And in North Dakota, both State and Federal leasing and royalty revenues go to the State's school fund.

(a) *Labor supply.*—A serious question raised by some analysts has been whether the supply of labor will, even with immigration, be sufficient to fill demand. It can be argued, for example, that coal-related employment will pay wages higher than the prevailing wages in other sectors. Labor could be bid away from these sectors by coal-related developments. This will be particularly critical to the agricultural and service sectors of the economy. Traditionally, these sectors have not been able to pay the level of wages that energy companies anticipate paying. It may be difficult for them to compete in the future labor market. Substantial substitution of capital for labor may be necessary in these sectors. It must be stressed that further empirical research is needed. Chronic labor shortages do, however, appear to be a reasonable possibility.

Table 5-4.—*Type of taxes and levels of Government to which the revenues accrue***

	State general fund	County general fund	School equalization or district fund	Long-range building fund	Other
Montana					
Strip coal mine tax	X	X			
State personal income	X		X	X	
Electric energy	X				
Corporation license tax	X		X	X	
Property tax (includes net proceeds)	X	X	X		
Resource indemnity tax†					X
North Dakota					
State corporate income	X				
State personal income	X				
Business and corporation privilege	X				
Sales	X				
Property	X	X	X		
Wyoming					
Severance	X				
Sales-service-use	X				
Conservation	X	X			
Property*					

*Revenues from this tax are divided between the local governments based on their mill levy, e.g., Foundation Program Fund, county tax fund, special district fund, and school tax fund.

†The Montana Resource Indemnity Trust Tax is levied on all mineral resources. The annual income may be legislatively appropriated to deal with local problems related to mineral development.

**Information for South Dakota and Nebraska was not included in the work group analyses.

(b) *Population.*–Over recent years, most of the rural areas of the Northern Great Plains have had a population decline. Despite the population decline in rural areas, there was growth in the larger cities and in those communities that are closely tied to energy development. For instance, during the 10-year period between 1960-70 Gillette, Wyoming, experienced a population increase of over 100 percent; Lame Deer-Ashland, Montana, had a population increase exceeding 27 percent while Stanton and Center in North Dakota had population increases of over 26 and 30 percent, respectively.

Although population growth is occurring in some areas[5] population densities are still quite low in the principal impact area as a whole. In 1970, the area averaged about 7 persons[6] per square mile compared to the national average of 67.

While many communities within the Northern Great Plains will be impacted by coal development and subsequent population increases, most of the immediate impact is likely to result in local communities where the plants will be located or where the employees reside. Communities like Gillette and Sheridan in Wyoming; Forsyth, Hardin, Colstrip and Lame Deer in Montana; and Beulah and Hazen in North Dakota all will be affected by coal development. Table 5-5 presents the projected population that would occur in these selected communities as a result of alternative levels of coal development. Presently, both Sheridan and Gillette in the Wyoming impact area are regionally important service centers. If CDP III occurs, Sheridan could become not only a major residential center for coal development in adjacent areas of Wyoming, but Montana as well, while Gillette has the potential of becoming the dominant wholesale, transportation, and service center for the entire Powder River Basin area.

(c) *Institutional and Community Services.*–The communities impacted by coal development are expected to experience a rapid growth in demand for urban services. None of the services in any of the counties that will be directly affected by construction of gasification plants are capable of handling an increased population without major adjustments. The type of adjustment, however, may not be as important as the rate of adjustment and many communities may find it difficult to adjust rapidly. It is likely that the smaller communities will be impacted the most,

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[5] This is based on the census definition where communities are considered urban if their populations are over 2,500.
[6] This compares to a regional density of 4.4 persons per square mile as described in land resource section.

Table 5-5.–*Population projections for selected communities CDP I, II, III–1980, 1985, 2000*

Town	CDP	1970	1980*	1985*	2000*
		All in thousands			
North Dakota					
Beulah	I	1	2	2	3
	II		2	5	9
	III		7	13	23
Hazen	I	1	2	2	3
	II		2	5	9
	III		8	13	23
Montana					
Hardin	I	3	3	3	3
	II		3	3	8
	III		3	8	23
Forsyth	I	2	3	3	3
	II		3	4	4
	III		4	5	6
Colstrip	I	0.4	3	3	3
	II		3	6	6
	III		6	10	13
Lame Deer	I	1	1	1	1
	II		1	1	1
	III		1	6	6
Wyoming					
Gillette	I	7	12	12	13
	II		14	19	21
	III		17	37	58
Sheridan	I	11	13	15	15
	II		16	23	31
	III		19	32	48

*Estimates represent an incremental increase over the 1970 level of population. The increase represents only the population associated with coal development as specified in the CDP's. Population increases that may be added by other activities have not been estimated.

since their ability to absorb growth and finance needed services are more limited than the larger communities.

Services provided by nonprofit organizations, including critical medical care will be strained by rapid population increases. This kind of service cannot be easily stretched and some communities are finding these services difficult to provide.

Publicly provided services such as education and municipal water services all require large capital outlays and long time periods to expand. The demand for education is instant upon arrival of workers' school-age children and presents one of the major problems the communities will face in coping with a rapid influx in population.

A number of services are financed largely through property taxes, but many construction workers will own little property and will leave before the industrial plant they are building is on the tax roles.

During the construction phase of development school enrollment will fluctuate greatly in the affected communities. More stable enrollment can be expected, however, during the operational phase. Schools built to serve construction-related families can be used to serve the families of operational personnel during the later development stages and at a time when revenues will be more readily available to help finance needed facilities.

In order to visualize coal-related educational needs in the impacted communities, the number of students that may be added to existing enrollment and the associated facility cost is provided in table 5-6. These estimates reflect requirements associated with the operational phase of development only.

In CDP I, impacts will be localized in communities near the plant and mine sites and in many areas existing capacity could be expanded to handle the anticipated growth.

The population increases projected for CDP II and III, however, are great enough so that even the larger towns located near the development will be affected. If the later stages of development in these higher coal development profiles occur, a whole set of new institutions would be required since the schools, police and fire protection services, and civic organizations would be so large that they would have to adjust. In other words, scaling has an upper limit where a change in kind as well as size will occur. This could bring about serious fiscal problems in those communities that do not have the physical capacity to handle an increasing population.

Table 5-6.–*Number of school age children and associated capital cost required to provide necessary facilities resulting from the operational phase of coal development–selected communities CDP II, III–1980, 1985, 2000*

	Number of students 1973-74	CDP	Number of students 1980	Cost millions of dollars	Number of students 1985	Cost millions of dollars	Number of students 2000	Cost millions of dollars
Buelah	500	II	300	1.3	1,300	5.1	2,600	10.3
		III	2,000	7.7	3,900	15.4	7,200	28.3
Hazen	190	II	300	1.3	1,300	5.1	2,600	10.3
		III	2,000	7.7	3,900	15.4	7,200	28.3
Hardin	1,700	II	130	0.5	130	0.5	1,600	6.4
		III	130		1,600	6.4	6,650	25.7
Forsyth	660	II	3,000	11.6	700	2.6	700	2.6
		III	700	2.6	1,000	3.9	1,300	5.1
Colstrip	340	II	1,000	3.9	1,600	6.4	1,600	6.4
		III	1,600	6.4	2,900	11.6	3,900	15.4
Lame Deer	340	II	0	0	0	0	0	0
		III	0	0	1,600	6.4	1,600	6.4
Gillette	3,100	II	2,300	9.0	4,000	15.4	4,600	18.0
		III	3,300	12.9	16,700	38.6	16,700	65.6
Sheridan	3,300	II	1,600	6.4	3,900	15.4	6,500	25.7
		III	2,600	10.3	6,900	27.0	12,100	47.6

For example, in CDP II, Gillette is expected to be the most affected community during the early stages of development but Sheridan will be more effected in the later years. Gillette's school enrollment would increase by 2,300 in 1980 and by another 2,300 by year 2000. Total capital cost of meeting these needs would be about $18 million. Sheridan's school enrollment would be about 1,600 in 1980 and increase to a total of 7,000 in year 2000. The total cost of providing these facilities would be about $26 million.

If CDP III were to occur, Gillette would be the most affected community throughout the development period. Approximately 3,300 students would be added to Gillette's school enrollment by 1980, almost twice present enrollment. Total enrollment would increase to 16,700 by year 2000. The estimated capital cost of providing facilities for these students would be $13 million in 1980, and $66 million by year 2000.

No data regarding governmental expenditures for the principal impact communities were available.[7] Suffice it to say, however, as population increases, stress will be placed upon existing service facilities and expenditures for facility expansion will be required. This will be particularly true for the later stages of development visualized in CDP II and III.

(d) *Housing.*—Regardless of what CDP level is assumed, coal-related growth will impact on the commercial service sectors of the Northern Great Plains communities. Of the many services that will be affected, housing will be the one of most critical importance.

In many Northern Great Plains communities, housing is already in short supply, particularly in towns like Gillette, Colstrip, Beulah, and Hazen which have felt or are beginning to feel the impact from energy development. Mobile homes are meeting the needs of many of the people and relieving the housing shortage to some extent. This is most evident in Gillette, where in 1973, about 35 percent of the town's 2,000 housing units were in mobile homes, and the number is rapidly increasing. The city is currently planning for a development of 380 new trailer homes during 1974.

In the future, mobile homes will continue to play a major role in meeting the housing demands of impacted communities. This will be most evident in the early years of development when as much as 70 percent of new housing may be composed of mobile homes. As development phases into maturity, however, the percentage of mobile homes can be expected to decrease and the number of permanent dwellings substantially increase. Even if 70 percent of new housing is mobile homes, a significant demand will be placed on the local construction industry to meet

[7] Although no governmental expenditure data were available from the communities, FY 1974 budgets for the six county area where the communities are located were as follows: Big Horn ($1.5 million), Rosebud ($2.2 million), Mercer ($1.2 million), Oliver ($0.5 million), Campbell ($3.4 million), and Sheridan ($3.2 million).

new home construction needs, for example, in Gillette the number of housing units would increase from 2,000 in 1970 to 4,000 by 1980, and 22,000 by the year 2000–CDP III. This represents an annual increase of 900 homes per year over the 20-year period. If 70 percent of these units are comprised of mobile homes, approximately 1,200 permanent housing units would be required by 1980 and another 330 annually during the next 20 years. This would place a tremendous demand on the local home building industry in Gillette, which in 1973 had about 40 new housing starts.

(1) *Operational phase.*–Housing needs of the various communities are summarized in table 5-7. As the estimates indicate, housing requirements will vary considerably by community and CDP. Housing needs for CDP I were not evaluated in depth; however, by the year 2000, a total of 2,000 additional housing units would be required to meet the demand in Gillette, and 1,000 additional units in Colstrip for CDP I. Other communities will be impacted but to a lesser degree.

Table 5-7.–*Increased housing needs for selected communities–operational phase development CDP II, III–1980, 1985, 2000*

Town	CDP	1970	1980	1985	2000
		All in thousands			
Buelah	II	0.5	0	2	1
	III		3	2	5
Hazen	II	0.5	0	2	1
	III		3	2	5
Hardin	II	1	0	0	2
	III		0	2	7
Forsyth	II		0	1	0
	III		1	0	1
Colstrip	II	0.4	1	1	0
	III		2	2	1
Lame Deer	II	0.5	0	0	0
	III		0	2	0
Gillette	II	2	3	2	1
	III		4	9	9
Sheridan	II	4	2	3	4
	III		3	6	7

Of the communities identified in the housing study, Lame Deer, Hardin, and Forsyth would be the communities least affected by coal development in CDP II. A CDP III, however, could require substantial expansion in all communities, generally after 1985. In CDP II, Lame Deer will not require additional housing in any time frame, but under the assumptions of CDP III, 2,000 units would be required by 1985, remaining at this level through the year 2000. Because of the anticipated development pattern, Hardin should not require coal-related housing until the year 2000–CDP II, but would require substantial expansion if CDP III were to occur–a total of 9,000 units in the 15-year period between 1985 and the year 2000.

Forsyth, a community which has experienced the expansion and contraction of the oil industry in the past decade, would be required to provide 1,000 additional housing units by 1985 with no further expansion anticipated through the year 2000–CDP II. In CDP III, 2,000 units would be required, 1,000 by 1980 and another 1,000 units by the year 2000.

Sheridan, Wyoming, would require the greatest number of housing units in CDP II with about 9,000 new units required between 1980 and 2000. Gillette, Wyoming, would require the greatest number if CDP III, requiring about 22,000 housing units during the same 20-year period.

(2) *Construction phase.*–Although the total housing needs associated with the construction phase of development have not been estimated, the increase in housing resulting from construction of a single gasification or powerplant has been determined (fig. 5-5). These estimates reflect a 5- and 3-year construction shcedule for a gasification and powerplant, respectively.

As figure 5-5 suggests, the housing needs of construction workers will fluctuate considerably and will significantly impact the communities affected by development. In fact, the demands will be even greater than those anticipated for the operational phase of development. The peak construction year could require three to four times the number of permanent employees needed in the operational phase and thus create substantially greater housing demands; although of relatively short duration.

(e) *Revenues.*–The ability of local governments to provide increased levels of service as well as new services may well become one of the most critical problems associated with coal development in the Northern Great Plains. Conceiveably housing and education may be the most visibly impacted service areas.

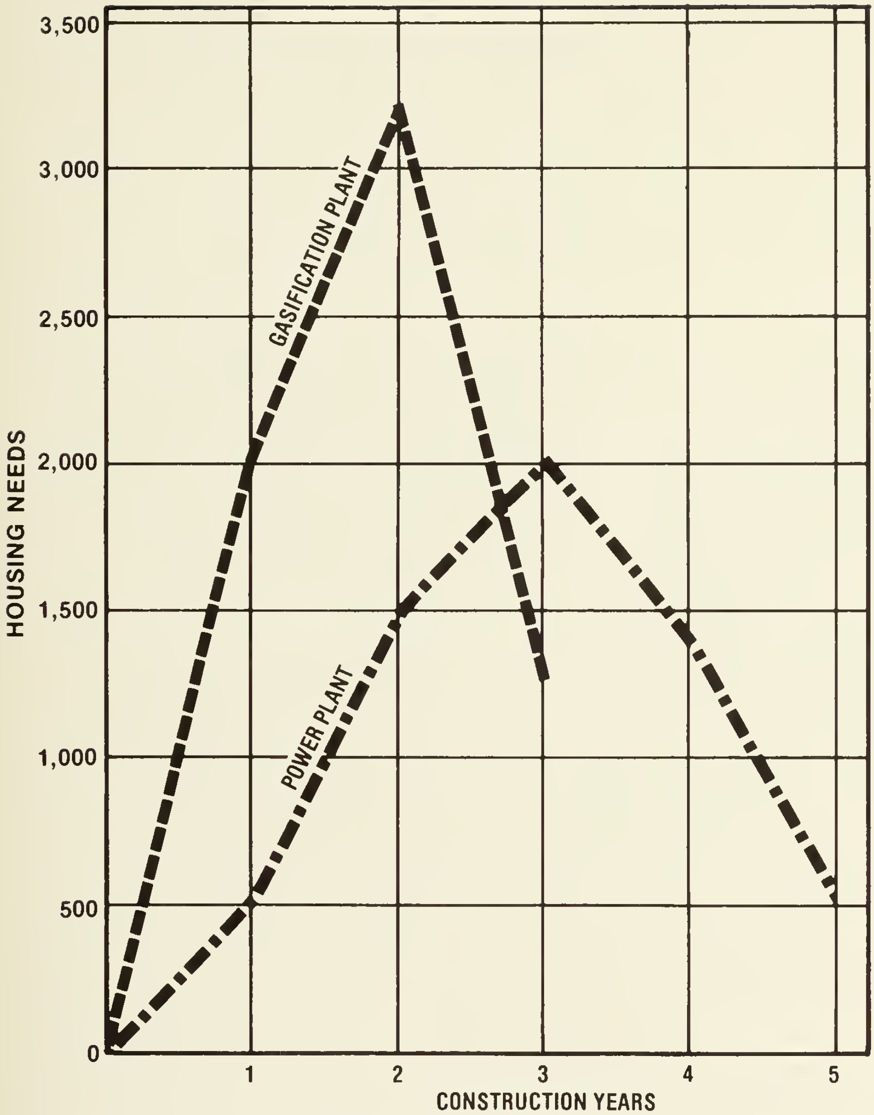

Figure 5-5. Housing requirements necessary to meet the needs of construction workers associated with a single gasification plant and powerplant.

Securing sufficient capital to expand classrooms and construct new schools and homes will be a very difficult obstacle to overcome in most instances. Complicating the above situation is the potential of a very high short-term demand for these services during the construction phase of coal development. The short-term demands potentially could become very severe in CDP II and further aggrevated to a heightened degree under CDP III levels.

Revenue–service demand lags, capital shortages, jurisdictional disputes, and a rapidly fluctuating population base have the potential for severely testing the structure of local government and non-governmental services. Additional study, and site specific development plans are needed before any firm cost estimates can be made and before any firm strategy to remedy these problems is undertaken.

(1) *Tax revenues.*–Funds to meet budget requirements will be one of the most critical problems the communities will face in their efforts to cope with rapid development. This will be most evident in the construction phase of development when coal-derived revenues will not be available for funding purposes. Assuming the state governments can effectively reapportion these revenues to local levels of government, prospects for financial relief seem good. Within a six county area[8] where revenues were estimated (assuming current tax rates and methods of taxation), new revenues generated annually in CDP I would be $44,000,000 in 1980 and approximately $88,000,000 in the year 2000. In CDP II annual revenues would be $47,000,000 in 1980 and $172,000,000 by the year 2000. Tax revenues in CDP III would be substantially greater: $76,000,000 in 1980 and $373,000,000 by year 2000.

The primary levels of government that will benefit from these new tax revenues include the county fund, local school district fund, and the state general fund. The state general fund and local school district fund are expected to benefit the most, claiming approximately 75 percent of all tax revenues. Other levels of government that will benefit, albeit to a lesser extent, include the county fund, School Equalization Fund, Long-Range Building Fund, foundation program fund, and the special district fund.

(2) *Coal royalty revenues.*–Coal royalties[9], although substantially smaller than tax revenues, will nevertheless be important.

Within the six county area, where over 85 percent of all coal royalty revenues would be generated, annual revenues in CDP I would total approximately $14,000,000 in 1980 and

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[8] Six-county area includes Rosebud, Big Horn, Montana; Sheridan, Campbell, Wyoming; Oliver, Mercer, North Dakota.

[9] Coal royalty revenues will be divided almost evenly between the State and Federal Governments, with the Federal royalty adjusted to account for the 37.5 percent amount that is required by the Mineral Leasing Act to be returned to the States. These revenues were estimated on the basis of a State and Federal royalty rate of $0.25 per ton.

increase to slightly more than $20,000,000 in year 2000. In CDP II, revenues would range from $17,000,000 in 1980 to $42,000,000 in year 2000. And, in CDP III, 1980 revenues would approach $22,000,000 annually, rising to $132,000,000 in the year 2000.

As illustrated here, the prospects for financing coal-induced service delivery systems seems quite good. Total revenues generated by year 2000 in CDP III may exceed one-half billion dollars annually. Sufficient tax revenues, however, will not be available to meet fund requirements during the construction phase of development and in the first few operating years. This time lag between revenue generation and service needs may place a severe budget strain on communities impacted by coal development. This problem is occurring in some NGP communities today.

5-4. *Impact on Indians as a Result of Coal Development.*—The Northern Great Plains five-state study area encompasses all or parts of 23 Indian reservations. These reservations contain Indian-owned land ranging from about 20,000 to millions of acres, and have Indian populations ranging from a few hundred to over 11,000. The reservations, in total, contain over 13 million acres of land, covering more than 20,000 square miles, an area considerably larger than many states. They provide a resource base for over 80,000 tribal members.

There is a great amount of institutional complexity regarding the Native Americans in relation to the rest of society in the Northern Great Plains. Indian reservations are independent political entities, each having its own political structures and legal codes. The states in which they are located have little if any jurisdiction within the reservation boundaries. The reservations represent a great diversity of subethnic groups, and differ significantly in their approach to socio-economic situations. They have historically been socio-economic as well as geographic islands in a region already isolated by great distances.

Services, normally the responsibility of local or state government in a non-Indian community, are performed in a cooperative effort between the various tribes, the BIA, and other Federal and State agencies. This includes a United States trust responsibility in the performance or assistance in the development, use, control, and protection of Indian lands and land-related resources as well as the construction, maintenance, and operation of irrigation systems and the development of recreational services and areas. Socio-economic services such as educational, health, and credit facilities are derived from BIA and the Public Health Service, as well as from standard Government and private sources.

On some reservations, over half of the Indian land is owned by the tribal entity. On others, the very large majority is in individual Indian allotments. The amount of Indian-owned lands decreased steadily during the first 65 years of this century. This occurred through cession to the Federal Government or by sale to non-Indian owners. During the past 3 decades, several tribes on the Missouri River have lost considerable amounts of land through eminent domain to large main-stem reservoirs. This erosion of land-ownership has been minimized in recent years, and most of the tribes are now taking specific steps to consolidate ownership, to acquire key tracts of land, and to further minimize land attrition by purchasing individual allotments that otherwise would be sold to non-Indians.

The land on the Indian reservations ranges from high forested mountain areas in Montana to semiarid grassland typified by several South Dakota reservations, as well as fertile irrigated river bottom valleys. Like non-Indian lands, some areas are underlaid by the Fort Union Formation, which contains huge coal reserves. Special attention is being given to the development potential and jurisdictional aspects of the Indian water and other mineral resources in the Northern Great Plains Region. The specific identification and quantification of these resources and rights is a major effort of the Native American Natural Resources Federation of the Northern Great Plains. A report by this Federation entitled "*Declaration of Indian Rights to the Natural Resources in the Northern Great Plains States*" is appended to this report.

(a) *The Six Most Affected Reservations.*—Table 5-8 shows the land area and population of the six reservations in Montana and the Dakotas that will feel the major social and economic impact from coal development. These six reservations are home for about 25,000 Indians and encompass over 5.6 million acres—an area larger than New Jersey. About equal acreage of coal rights lie partly within and partly outside the reservations. These coal reserves probably amount to billions of tons.

(b) *Population.*—All six reservations have experienced a significant population increase in the last 10 years (table 5-9). The Indian population increase contrasts sharply with the overall population changes that occurred in the states where the six reservations are located.

Table 5-8.–*Indian land and residents, by reservation, 1973*

Reservation	State	Indian-owned land (acres)*	Indian resident population
Crow	Montana	1,562,077	4,334
Fort Peck	Montana	961,857	6,202
Northern Cheyenne	Montana	434,420	2,926
Fort Berthold	North Dakota	420,718	2,775
Standing Rock	North Dakota, South Dakota	846,684	4,868
Cheyenne River	South Dakota	1,405,178	4,335
Total		5,630,934	25,440

*Acres include land both on and off the reservation. Source: Bureau of Indian Affairs (1974).

(c) *Age.*–The reservation residents are quite young; nearly half of them are under 16 and nearly two-thirds are under 25 years of age. Separate analysis of the 1970 census shows that about 40 percent of the population in both Montana and South Dakota were under 19 years of age. The Indian population of the six reservations in this category range from 53 percent on the Crow Reservation to about 62 percent on the Fort Peck Reservation.

The high percentage of the Indian population in the younger age groups, compared to the relatively low populations in the group 45 years and older, indicates a considerable potential for an increased Indian labor force. It also contributes to a high degree of dependency, with over half of the total population being either under 16 years of age or over 65 years of age.

Table 5-9.–*Indian population change, 1963-73*

	Population		Percent increase
	1963	1973	
Crow	3,678	4,334	17.8
Fort Peck	3,390	6,202	82.9
Northern Cheyenne	2,166	2,926	35.1
Cheyenne River	3,421	4,335	26.7
Fort Berthold	2,408	2,775	15.2
Standing Rock	4,300	4,868	13.2
Total	19,363	25,440	31.4

Source: Bureau of Indian Affairs (1974).

(d) *Labor Force and Employment.*—All six reservations have higher unemployment rates than the states where they are located. The 1970 unemployment rates reported by the Bureau of Labor Statistics for NGP reservations ranged from 11.6 percent to 29.1 percent. Comparable rates for Montana were 6.3 percent; for North Dakota, 4.6 percent; and for South Dakota, 3.3 percent (table 5-10).

Current Indian employment is primarily in agriculture, government, and tourism. The Northern Cheyenne also have a significant number of people employed in logging and milling. These skills provide the only nucleus for developing the Indian manpower for employment in the coal-related industries. If the Indian labor force is to be employed in coal industries, many of them will need to learn new skills. This assumes that members of the Indian labor force will actually seek employment in coal industries. The high unemployment rates on the reservations indicate that they would.

Table 5-10.—*Unemployment Rates: North Dakota, South Dakota, and Montana, compared to Indian reservations within their boundaries, 1970*

Area	Percent unemployment
Reservations	
Crow (Montana)	11.6
Fort Peck (Montana)	25.7
Northern Cheyenne (Montana)	11.1
Cheyenne River (South Dakota)	18.4
Standing Rock (North Dakota-South Dakota)	29.1
Fort Berthold (North Dakota)*	—
States	
Montana	5.5
North Dakota	4.6
South Dakota	3.3

*Data for Fort Berthold were not available.

Source: Bureau of Labor Statistics, U.S. Department of Labor.

However, many Indians are concerned about the adverse social and economic changes that coal development may bring and this may influence their decision regarding employment in the strip mines, and power and gasification plants.

(e) *The Indian Family and Income.*—On the six reservations, Indian family size is larger, family income is lower, and a greater percentage of Indian families are in poverty than are found in the population standard of the six states where they are located, or in the U.S. population. These large families and low incomes are reflected in the percentage of the families having an income below the poverty level (table 5-11).

Table 5-11.—*Family size and income: Indians compared to total population*

Area	Average family size	Median family income	Families with incomes below poverty level
	Persons	Dollars	Percent
Reservations:*			
Crow	6.60	5,260	40.0
Fort Peck	6.54	5,136	46.7
Northern Cheyenne	5.37	5,270	39.8
Cheyenne River	5.99	3,857	54.8
Fort Berthold	6.10	4,800	45.3
Standing Rock	5.38	3,667	58.3
States:†			
Montana	3.55	7,494	10.4
North Dakota	3.72	7,838	12.4
South Dakota	3.66	8,512	14.8
U.S. (all families†)	3.62	9,433	10.7

*Data from Bureau of Indian Affairs (1974).
†Data from 1970 Census of Population.

(f) *Educational Levels.*—Educational levels on the six reservations are significantly lower than those for the total populations of the states in which these reservations are located. A brief comparison from U.S. census data for the Crow and Standing Rock Reservations shows the median educational level of Indians over 25 years is almost 3 years less than non-Indian NGP residents.

(g) *Anticipated Reservation Coal Development.*–The Standing Rock and the Cheyenne River Reservations have combined coal reserves estimates at some 100 million tons. However, commercial exploitation is considered marginal, and mining companies have thus far shown little serious interest in development.

Fort Berthold Reservation is reported to have between 4 and 20 billion tons of measured and indicated lignite reserves, much of which is commercially recoverable under present technology. However, members of the three affiliated tribes have expressed great concern about the cultural and environmental issues accompanying coal development and have imposed an indefinite moratorium on leasing and other mineral activity.

The Fort Peck Reservation in eastern Montana has strippable lignite reserves estimated at several billion tons. However, coal developers have shown little interest in them, and no leasing or prospecting activities are currently underway.

The Northern Cheyenne Reservation also has huge coal reserves, estimated in excess of 5 billion tons of strippable deposits. However, tribal leaders and members are presently discouraging any development activity until the social and environmental effects of coal development are more fully understood. Testimony presented by the Northern Cheyenne Landowners Association at hearings regarding coal development conducted by U.S. Senator Lee Metcalf from Montana in April 1974 illustrates their concern:

> "The imminence of strip mining on the Northern Cheyenne Indian Reservation is bringing about a questionable future for the resources and Indian lands as well as the lives of the people exposed to it. The magnitude, nature, and rapidity with which this development will be brought upon the Cheyenne can only be felt as modern day genocide."

The Crow Reservation is the only one of the six where coal development is in progress. It should be pointed out that although the Crow have initiated contractual agreements with mining interests to extract coal from ceded lands adjacent to their reservations, there is diversity of opinion among members of the tribe as to the desirability of coal development on the reservation. Public hearings held at the Crow Agency, Montana, in November 1973, produced testimony by tribal members both for and against coal development.

Arrangements have already been made with Westmoreland Resources to mine at least 77 million tons of Crow-owned coal on Sarpy Creek in the ceded area which lies immediately north

of the present boundaries of the Crow Reservation. A final environmental impact statement relating to that mining operation has been prepared and filed.

In addition, the Crows have either prospecting permits or leases with American Metals Climax Company, Gulf Minerals Resources Company, Peabody Coal Company, and Shell Oil Company. Explorations by these companies indicate a total of 4 to 4.5 billion tons of coal considered strippable under present economic and technical levels.

Significant employment opportunities for Crow Indians may become available in coal-related industries on or adjacent to the Crow Reservation. If only two or three strip mines are operated, the work force would conceivably be mostly Indians, since they are assured preferential hiring and assuming they seek work in the mines. However, a significantly higher level of development may require very high non-Indian employment. This implies the possibility that the Indians might become a minority on their own reservation unless specific residential controls are exercised. To attempt to alleviate this problem, the Crows have been assured preferential hiring status in the coal industry.

The potential impact of coal development on the culture and lifestyle of the different NGP Indian tribes has not been adequately explored. A complete knowledge of the culture and lifestyle of the Indian is a prerequisite of such an impact study. The only people having such knowledge are the tribal members; therefore it is logical to assume that they should be responsible for determining the potential beneficial or adverse impacts coal development may have on their culture and lifestyle. Many tribes have been struggling to develop the capability of making these studies and communicating the results to non-Indians. To date, this effort has been only marginally successful. In recent months, the Native American Natural Resources Development Federation of the Northern Great Plains has been organized by the NGP tribes to begin to address in a cooperative way the mutual problems the tribes are confronted with. A high priority need of this group is the description of their natural and cultural resource base and the protection of their water rights. If this group is successful, it may provide answers to many of the questions related to the issues raised in this section of the report.

5-5. *Agriculture and the Changes Expected From Coal Development.*—Within the agriculture study area which includes portions of the four states of Wyoming, Montana, North Dakota, and South Dakota there are approximately 91 million acres of land, of which approximately 24

million acres are classified as cropland and 70 percent or 63 million acres is in pasture or rangeland. Of the cropland, 97 percent or 23 million acres is nonirrigated and 694,000 acres or the remaining 3 percent is under irrigation. Presented in table 5-12 is a summary of total land use in the study area.

Within the study area there are 37,920 farms and ranches ranging in size from an average of 815 acres in Ward County, North Dakota to 11,105 acres in Natrona County, Wyoming. The farms and ranches average approximately 2,400 acres in size with the average size of a farm in Montana—3,771 acres; North Dakota—1,294 acres; South Dakota—3,598 acres; and Wyoming—6,329 acres.

As of January 1, 1972, nearly 3.75 million head of cattle and calves stocked the farms and ranches, sheep and lambs numbered about 2 million, while hogs totalled slightly more than 300,000.

Wheat is the principal crop grown in the study area, and occupies about 30 percent of the total cropland under production. In 1971, slightly more than 130 million bushels of wheat averaging 20 bushels per acre were produced on approximately 6.5 million acres.

Other major crops produced in the study area include barley, flax, oats, corn, alfalfa, and sugar beets. Smaller acreage of potatoes, soybeans, sorghum, rye, and beans are also produced within the area together with poultry and dairy products.

5-6. *Agricultural Impact Assessment.*—Coal development will affect Northern Great Plains agriculture in three principal resource areas—labor, water, and land. The method of mining, the level of development, and the method and location of coal utilization will determine to what extent agriculture will be affected.

(a) *Labor.*—Strip mining will compete directly with agriculture for labor resources as both industries place a premium on men in their physical prime who are accustomed to working with machinery and to working long hours outdoors.

Operators of small farms who are underemployed in their farm businesses will provide a limited labor source for industry. It is expected that some of these operators may take advantage of the new off-farm job opportunities that industry provides and shift themselves and their families into higher levels of income while operating their farms on a part-time basis. Others may leave agriculture entirely, taking advantage of the higher income levels that coal-related industry will provide. Operators who are fully employed with adequate income from farming and ranching

Table 5-12.–*Land use summary–NGP study area by state–in millions of acres**

Total land area acres	Cropland				Pasture and rangeland	Percent of total	Forest and woodland	Percent of total	Urban and built-up	Percent of total
	Irrigated	Percent of total	Non-irrigated	Percent of total						
Montana 34,625.9	361.4	1.0	5,923.1	17.1	26,419.9	76.3	1,649.2	4.8	272.2	.8
North Dakota 25,840.2	55.1	.2	14,650.3	56.7	10,434.3	4.4	154.4	.6	546.0	2.1
South Dakota 11,556.1	64.6	.5	1,757.4	15.2	9,548.4	82.6	154.6	1.3	31.1	.3
Wyoming 18,858.9	212.4	1.1	484.0	2.6	16,140.1	85.6	1,716.8	9.1	305.6	1.6
NGPRP study area 90,881.0	693.6	.8	22,814.8	25.1	62,542.7	68.8	3,675.0	4.0	1,154.9	1.3

(Overall source: U.S. Census of Agriculture, 1969, plus published and unpublished federal agency data. Land use statistics may exceed state acreage totals due to the grazing of forest lands.)

*The 90,881 million acre study area for the agricultural analysis varied slightly from the 91.5 million acres Surface Resources Work Group study area.

and who do not hire much extra labor will be affected least by labor market changes. They likely will not be attracted to off-farm work and higher wages for hired labor will have little effect on their operation. However, those operating large farms and ranches and hiring large amounts of labor will probably be forced to make significant adjustments in their operations particularly at the higher levels of coal production as envisioned under CDP II and III. These adjustments which may or may not be considered desirable may include dropping certain labor-intensive enterprises, adopting labor-saving techniques, and perhaps even reducing the size of their farming operation.

An overview of the affect that coal development will have on the labor resources in the Northern Great Plains suggests that the supply of labor available to agriculture will be reduced. This will not cause major changes in farm organization in southwestern North Dakota, although the trend toward fewer and larger family farms based on labor-intensive enterprises, such as small grains and beef cattle, will likely be accelerated. Other parts of the Northern Great Plains will experience similar effects. Large ranching enterprises, like those located in some parts of Wyoming and Montana that are based largely on hired labor, may experience difficulty in hiring and retaining capable workers in competition with an expanding coal industry.

(b) *Water.*—The amount of water necessary for coal development even at the CDP III rate of development may not necessarily compete with water used in existing agriculture production. However, conflict between agriculture and industry over future use of water that is beyond presently established uses and future coal development needs of the area may occur. It should be noted that industry is purchasing farms and ranches and converting the agricultural water right to industrial use. A discussion of this is presented in the Water section, part IV-2.

It has been estimated that more than 3.0 million acre-feet of water is available, with new storage, in the Upper Missouri River Basin to meet future water requirements. Of the 3.0 million acre-feet that could be made available, 800,400 acre-feet is needed for CDP III. The balance, ostensibly, could be used to serve other uses including new irrigation development. Water use in the Yellowstone basin above the CDP II level of coal development would require additional storage facilities, however, to provide water above that needed for minimum flows.

In 1970, there were about 694,000 acres of land under irrigation in the 63-county study area and little expansion has occurred since that date. With the current deemphasis on new Federal irrigation development, it is not expected that the irrigated base will, within the study area,

increase substantially in the near future. Presently, within the Yellowstone River Basin there are no projects which are being studied for new development that would meet Federally funded economic justification. There is some potential for new State-assisted and private irrigation development in the Yellowstone River Basin, but this is not expected to exceed 100,000 acres.

North and South Dakota are each planning Federally funded projects that will expand their irrigation base, but these projects are outside the study area, and have been previously authorized under different formulation criteria.

(c) *Land.*–More land will be removed from agriculture production as more coal is mined. Overall, however, it is not anticipated that industrial disturbances of the land will have a major effect on the area's agriculture productivity.[10]

Under CDP II, for each of the years between 1985 and 2000, there would be approximately 130,000 acres of land displaced.[11] This represents a 242 percent increase from the 38,000 acres assumed to be disturbed in CDP I and 138 percent less than the 309,000 acres would be disturbed if CDP III occurs. The amount of land displaced relative to the total land area of 91 million acres is 0.04 percent in CDP I, 0.14 percent in CDP II, and 0.34 percent in CDP III. Table 5-13 summarizes the amount of land that would be disturbed in all study area counties by profile and by time frame.

The plant and mine sites are located almost entirely on rangeland. Therefore, it is not expected that irrigated agriculture will be affected and only a small percentage of the dry cropland in the study area would be disturbed. Table 5-14 summarizes the annual displacement of cropland in the study area in terms of production and acreage disturbed, beginning in 1980–CDP III. Only land assumed to be affected under CDP II and CDP III have been projected. Under CDP I, only a minor amount of cropland would be displaced.

The loss in wheat production, which is the principal crop grown in the study area, would be approximately 2 percent of the total wheat being produced under CDP II and 4.5 percent (0.3 percent national production) under CDP III. Barley and oat production would be affected but only to a relatively minor degree.

The loss in vegetation to support cattle production in the Northern Great Plains area is minimal. For example, the level of surface mining indicates that a total of approximately 224,000 acres of rangeland would be unavailable for grazing in year 2000. This includes natural

[10] Under the assumption that National Ambient Air Quality Standards have been adequately set to protect public health and welfare (including damage to vegetation and animal life) and that these standards will be enforced, no impacts of air pollution on agriculture are anticipated. It should be noted however, that effects of some trace elements on vegetation are not fully understood and that standards have not been set for these elements.

[11] This represents the total amount of land out of production at any one time.

Table 5-13.–*Cumulative agricultural acres displaced as a result of coal development in the Northern Great Plains Study Area CDP I, II, and III**

	CDP I			CDP II			CDP III		
	1980	1985	2000	1980	1985	2000	1980	1985	2000
Fixed acres out of production for plant sites, etc. (acres)	4,100	4,100	4,100	25,300	25,300	25,300	60,700	60,700	60,700
Crop and rangeland being disturbed (acres)	19,000	33,500	33,500	65,000	104,300	104,300	148,100	247,900	247,900
Total acres disturbed	23,100	37,600	37,600	90,300	129,600	129,600	208,800	308,600	308,600

*Acres do not correspond directly with total acreages disturbed shown in Part IV as they were based on different assumptions of when mines and plants would begin operation and because allowance was made for being rehabilitated to cropland productivity after 5 years.

grazing lands currently being mined, and that which is in the process of rehabilitation following mining, as well as the acreage more-or-less permanently occupied by mine facilities, transmission lines, and other coal-related uses. At a rate of 3 acres per animal-unit-month (AUM), an equivalent of the grazing needs of only 6,200 animal units on a year-long basis would be lost.

Statistical Reporting Service data on 1972 livestock numbers, converted to an animal-unit-basis, indicate a total of 3,178,410 animal-units of cattle, calves, sheep, and lambs in the region. Therefore, the total animal-units displaced by mining activities at the CDP III level of development in year 2000 would be only 0.0019 percent or less than 2/10 of 1 percent of present livestock numbers in the region. The value of the grazing lost, at a rate of $6 per AUM, would total $447,700 in year 2000 (table 5-15).

Table 5-14.—*Cropland and associated production displaced annually between 1980 and 2000-CDP II and III*

CROP	CDP II		CDP III		
	Acres displaced	Production* bushels	Acres displaced	Annual* production bushels	Value† dollars
Wheat	13,807	276,140	28,400	586,000	714,000
Barley	1,205	44,505	2,878	106,500	87,300
Oats	3,866	193,300	7,328	366,400	172,200
	18,878	513,945	38,606	1,058,900	974,500

*Based on 1971 average annual yield—wheat 20 bu./acre; barley 37 bu./acre; oats 50 bu./acre.
†1971 weighted average seasonal price for Montana, Wyoming, and North Dakota as follows: wheat—$1.22/bu; oats $1.47/bu; and barley—$0.82/bu. (more recent values for these commodities would be considerably higher.)

Table 5-15.—*Total acres of rangeland displaced in study area and value foregone 1980-2000, CDP's I, II, and III*

Item	CDP I			CDP II			CDP III		
	1980	1985	2000	1980	1985	2000	1980	1985	2000
Mined to date	4,500	10,600	34,200	4,700	13,000	70,300	6,800	26,500	157,400
Mining facilities	1,400	1,400	3,200	1,800	8,600	19,000	7,500	21,200	45,500
Permanently out	—	—	—	—	—	—	—	—	17,800
Temporarily out	—	—	—	—	—	—	—	—	71,700
Total Rehabilitation	—	-1,000	-19,700	—	-1,000	-32,500	—	-1,500	-68,500
Net acres out of production	5,900	11,000	17,700	6,500	20,600	56,800	14,300	46,200	223,900
AUM grazing @ 3 ac/AUM*	2,000	3,700	6,000	2,200	7,000	19,000	4,800	15,400	74,600
Total animal units—annual*	200	300	500	200	600	1,600	400	1,300	6,200
Grazing value @ $6.00/AUM	12,000	22,100	35,500	13,000	42,000	113,700	28,700	92,500	447,700

*Total may not be exact due to rounding.

Table 5-16 summarizes the number of animal units of grazing that will be affected in the five-county area as compared to the region as a whole. This is followed by table 5-17 which summarizes by time frame the amount of grazing land taken out of production and the value foregone as a result of coal development in the five-county primary impact area.

Table 5-16.—*Total animal units (AU) of grazing in five-county concentrated area and displacement—year 2000*

Area	Animal units January 1972	Animal units displaced	Percent of present AU's
	All units in thousands		
Campbell County, Wyoming	87,700	1,000	1.08
Big Horn County, Wyoming	98,500	700	0.67
Rosebud County, Montana	79,100	900	1.18
Mercer County, North Dakota	76,700	600	0.78
Oliver County, North Dakota			
Total four sample counties	342,000	3,200	0.92
Region Total	3,178,400	6,200	0.19

Approximately one-half of the impact to the land in the Northern Great Plains will be experienced in the five-county area of Rosebud, Big Horn Counties, Montana; Campbell County, Wyoming; and Oliver and Mercer Counties, North Dakota, where most of the mining activities are expected to be located (table 5-17). In this five-county area by year 2000—CDP III, 3,200 animal units of grazing valued at $226,000 are estimated to be displaced by coal development. This represents about 0.92 percent of the total, 342,000 AUM's of grazing in the five-county area.

As indicated here, the impact of coal production on agriculture in the aggregate will be relatively insignificant. The impact from mining, however, will be much more severe on an individual livestock operating unit basis. A single surface mine, with its attendant facilities, could displace a significant portion or all of an operating unit. A large mine operation, for instance, could affect several adjacent livestock units and the impact in such cases could be so extensive that the operating unit would cease to exist.

The value of an individual tract or acreage to a livestock operating unit is frequently not based directly upon the productivity of that tract, but that the tract provides forage during a critical

Table 5-17.–*Total acres of rangeland displaced in five-county concentrated impact area and value foregone–1980-2000, CDP's I, II, and III*

Item	CDP I			CDP II			CDP III		
	1980	1985	2000	1980	1985	2000	1980	1985	2000
Mined to date	4,500	10,600	34,000	4,600	12,300	55,800	5,700	20,000	110,300
Mining facilities	1,400	1,400	2,900	1,700	6,800	10,900	5,000	16,100	29,000
Permanently out	—	—	—	—	—	—	—	—	8,100
Temporarily out	—	—	—	—	—	—	—	—	19,900
Total rehabilitation	—	-1,000	-19,700	—	-1,000	-27,800	—	-1,500	-53,900
Net acres out of production	5,900	11,000	17,300	6,300	18,100	38,900	10,700	34,600	113,400
AUM grazing @ 3 ac/AUM*	2,000	3,700	5,800	2,100	6,000	13,000	3,600	11,500	37,800
Total animal units–annual*	200	300	500	200	500	1,100	300	1,000	3,200
Grazing value @ $6.00/AUM*	11,800	22,100	34,500	12,600	28,200	77,800	21,500	69,200	226,800

*Total may not be exact due to rounding.

period of the year when no other forage is available. It may, therefore, be an essential link in the year-round livestock operation, although it produces a small amount of the year-round forage supply (for example, the spring lambing range for a sheep unit or a subirrigated meadow which can be grazed when upland ranges are dry).

An added "nuisance factor" would have to be taken into consideration also. This element would affect grazing values when a portion of a livestock operating unit is diverted to a nongrazing use such as surface mining. The location of the development in relation to other lands and to livestock handling facilities is important. If a mining development was located at the outside edge of a large grazing unit, it may have little effect other than reducing acreage available for grazing. If, on the other hand, the mining development was located near the center of a livestock ranch, it could seriously interfere with movement of livestock fencing and pasture arrangement, livestock water supplies and distribution, animal performance, and in general disrupt the overall farm operation.

5-7. ***Societal and Cultural Impacts of Coal Development.***—Fundamental to the culture and way of life of persons who live in the NGP is the agricultural use of land. This culture is dominated by three distinct groups of people; farmers and ranchers, townspeople, and Indians. The first two groups share one culture while the Indians have a separate, yet related culture.

To understand the impact of coal development on the culture and lifestyle of NGP residents we must understand the process by which a rural society becomes urbanized. The term "urbanization" can be described as a process which changes the way people relate to one another. As urbanization occurs, residents become less oriented toward other individuals in the community and more oriented toward institutions and extra-community forces. It includes a general decline in local autonomy, exposure to different norms, and the destruction of the existing social order and the building of a new one.

The non-Indian culture and way of life is centered around two features—the small size of the communities and the agrarian nature of the society. The persons who live in the area are accustomed to a generally slow pace of living, relatively little congestion, a well-integrated, stable society with an established sense of community where individuals are known and most face-to-face contact is with familiar persons, in short most of the attributes of a "primary"

community. Agriculture has long been the principal economic force in the area and the region's culture is firmly rooted in the American agricultural ideology.[12]

Initially, the impacts of urbanization will be greatest on the persons and communities closest to the actual development sites, with the impacts then diminishing in a descending scale with distance from the development sites. In the long run, however, all persons in the area will be affected. The smaller the scale of development, the more likely it is that the impacts will be localized.

Probably one of the major impacts will be the sheer size of the population growth within a very short time. Large numbers of persons with different values and orientations will move into the area because of the developmental activities. Most will likely move into rather small communities, doubling, tripling, or even quadrupling the present population. Congestion, crowding, the physical and mental stress associated with these phenomenon are all likely to be severe in many parts of the region, and most severe during the short-term construction period of development. All of these impacts are likely to reduce the perceived quality of life for many of the people already living there.

With these changes, many residents, landowners as well as others, are challenged to modify their current life styles in order to accommodate changes in their environment. Some persons on fixed incomes (i.e., retirees) may be dislocated because of an increase in the cost of housing. Sportsmen may find favorite recreational areas disrupted by mining activities or "overcrowded" by newcomers.

The changes in the culture and way of life of the area that may follow the development will vary not only with the level of development which occurs, but with the pace of that development. One likely set of impacts which will follow rapid development might be termed the "boom town" syndrome.[13] Gilmore and Duff describe the syndrome as a "whole family of mental health symptoms and problems" that results from the rapid influx of a great many people. Families are crowded together in mobile homes in a strange environment; newly arriving families, particularly the blue collar families, seek acceptance into the community; social cohesion suffers as alienation and emotional distress feed on each other; and crime rates, suicide attempt rates, and alcoholism tend to increase. In short, the quality of life of persons, both newcomers and residents of the area, is degraded.

[12] See for example, Edward Higbee, *Farms and Farmers in an Urban Age* (New York: Twentieth Century Fund, 1963) and Robert H. Salisbury, "Agriculture and Natural Resources," in J. W. Peltason and James M. Burns, *Functions and Policies of American Government* (Englewood Cliffs, N.J.: Prentice-Hall, 1967).

[13] John S. Gilmore and Mary K. Duff, "Statement to Public Lands Subcommittee, Interior Committee, U.S. Senate, Jan. 19, 1974" (Denver: mimeo, 1974) p. 10.

Of course, the boom might turn into a "bust" if exogenous factors force the closing of mining activities in the area. This, then, would lead to another series of impacts for the communities involved.

The family as a social unit, is likely to be greatly affected by the changes introduced by the energy development activities. Traditionally, the rural family has been a strong social unit. In the rural setting, cohesiveness of the family is both the result of and mandatory for economic survival.[14] With the advent of urbanization and industrialization in the NGP, the family is likely to cease to be a basic unit of production. Individuals may seek employment outside of traditional family enterprises, such as the family farm, ranch, or store. Extended families within one household are less likely to exist as people migrate to other employment.

These new values and interests often change existing values and culture. Such change generates stress on the residents, leading to a feeling of isolation, and sometimes alienation and conflict between established groups and newcomers. In other words, conflicts between some ranchers and miners could develop. Some communities might be "taken over" by newcomers, and long-term residents may withdraw physically or in terms of participation in community activities.

As the newly emerging community stabilizes it may present new job opportunities and a higher economic standard of living than was possible in the old community. The variety of cultural and recreational opportunities would probably increase as would the availability of services.

High emigration rates have existed throughout virtually the entire region for the past several decades, for almost all age groups.[15] One expected impact of development is that the emigration rates would be significantly reduced, in large part because of the increased availability of desirable employment opportunities within the area. If this is to occur, then an additional measure of stability in terms of the residents could be anticipated.

Most of the rural communities of the area have well defined and long established networks of social and political relationships. It is likely that one of the results of the anticipated changes in the area will be the fragmentation of these groups by the intrusion of relatively large numbers of persons into the area, and in effect, the creation of a new social order. Another likely impact will be the dilution of political power of the historically dominant groups (primarily landowners) within the impacted area. In the long run, new political alliances and groups will likely develop.

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[14] Sam Carnes, "Report to Work Group" (Evanston, Ill.: mimeo, 1974), p. 11.

[15] Professor Audie Blevins, personal communication, April, 1974.

A further major change in the way of life for some of the people in the area has been an increased social activity in planning and organizing for anticipated change. In effect, the anticipated environmental changes have resulted in activating groups and leaders into overt action. Many people who previously had not participated in community, civic, or political affairs have devoted large amounts of time and energy to organizing and participating in community affairs related to forthcoming development.

Some of the impacts have already begun to occur. There has been some population growth and preliminary activities such as securing leases and mapping resources have begun to spur some changes in the area. One notable change among a sizable group of the population has been the creation of an aura of uncertainty and "unsettledness" about their future. Questions such as the following occur: "How much development will take place?" "When will the development take place?" "How fast?" "What will happen to the water table?" "Can the land be reclaimed effectively?" No longer can many people view the future in the same manner as they have for many years. Uncertainty about the future has materially reduced the quality of the present for many persons.

In sum, the culture and way of life of persons in the impacted areas of the NGP will likely shift from the agrarian focused way of life which now exists to a larger, more urbanized way of life with all the advantages and disadvantages which that will entail. Some of the changes would likely come about without the energy development activities, but at a very much slower pace—over decades instead of in a few years.